BEST COPY AVAILABLE

11/9/83
C8650-4A

Volume 61, Number 11
November 1983

09A35 1984293 W 2 2077
SUITE 800 COPY # 2
STATISTICAL REFERENCE IND
CONGRESSIONAL INFO SVC D
4520 EAST-WEST HWY STE 800
BETHESDA MD 20814

Electric Light & Power
THE NEWS MAGAZINE OF ELECTRIC [illegible]ITY MANAGEMENT AND TECHNOLOGY

OG&E is '83 Utility of Year

Company is selected because of its solid, consistent financial performance and all-around system strength

BARRINGTON, IL—Oklahoma Gas & Electric Co. has been selected by *Electric Light & Power* to be the recipient of its 15th annual Electric Utility of the Year award. Announcement of the company's selection was made by *EL&P* Editor-in-Chief Robert A. Lincicome.

The Oklahoma utility was selected for outstanding performance on behalf of its customers, employees and shareholders.

The Special Report on the 1983 Utility of the Year begins on p.11

Specifically, said Lincicome, OG&E was chosen for the award because of solid financial performance in 1982 and for its continuing program to shift its fuel dependence away from locally available natural gas, as well as for aggressive conservation and load management programs, improved productivity and its efforts to get employees more personally involved in the company ownership.

Last year OG&E reported net income gains of $26-million, or 32.9 percent, to $105.1-million, on revenue gains of 9.9 percent to $907.6-million. Earnings per share increased 25 percent, to $2.57. Both system sales of electricity and the number of customers were up.

Moreover, the company's stock price rose substantially above book value, its securities were upgraded, the quality of its earnings were strengthened and the capital structure was improved.

The company's performance was the result of hard-headed conservative management, led by Chairman and President James G. Harlow, Jr., building on decisions made by company management as long ago as 1969. In 1969, OG&E management, headed up by Donald S. Kennedy, looked at the long-term outlook for fuels and decided to shift its dependence away from natural gas to coal, despite being located right on top of one of the world's largest sources of natural gas. OG&E also decided at the time not to join the industry's swing to nuclear generation, despite what then appeared to be the promise of low generation costs.

As a result, today OG&E is involved in constructing only coal-fired additions to its baseload generating system. Moreover, that program is winding down, which has allowed the company to improve the quality of its earnings. Allowance for Funds Used During Construction has been reduced to less than 19 percent of Net Income and 69 percent of its 1982 capital requirements were provided by internal generation. Because of the improvement in the solidarity of its earnings the price of the company's stock rose to 113 percent of book value, earnings per share of common stock rose to $2.57 and dividends to $1.78, and the company's securities were upgraded by Standard & Poors.

Oklahoma Gas & Electric Co. is the 15th company to be selected for the annual *EL&P* award. Last year's winner was Wisconsin Electric Power Co. and the winner in 1981 was Atlantic City Electric Co.

When construction work on Muskogee 6 is completed, OG&E's baseload generation system construction program will come to a halt. The 1983 Utility of the Year award winner was 100-percent dependent on natural gas for fuel as late as early 1977, but will be approximately 50-percent coal-fired upon completion of the last Muskogee unit. A Special Report about this year's award winner, and its management team, programs and accomplishments, begins on page 11.

U.S. energy policy: business as usual for Reagan team

WASHINGTON, D.C.—There are few surprises contained in The National Energy Policy Plan the Reagan Administration has sent to Congress.

The by-now generally understood, if not enthusiastically embraced, market approach to energy demand and supply is reiterated in the exceptionally brief document, with a very general emphasis on current legislative initiatives in the areas of natural gas and nuclear regulation.

The administration says these initiatives are particularly important in "maintaining an energy supply system that will continue to provide an adequate supply of energy at reasonable cost."

Reagan 'committed' to decontrol

Earlier this year the administration proposed the Natural Gas Consumer Regulatory Reform Amendments of 1983. The proposal reportedly has as its aim "ensuring consumer protection for natural gas users, deregulating natural gas prices at the wellhead by a date certain to capture the benefits of competition in the marketplace, and adjusting contract provisions entered into in a regulatory environment".

Noting that Congressional committee action has taken place in both Houses that has lead to bills differing from the administration's proposal, The National Energy Policy Plan declares, "The Administration is committed to continued cooperation with Congress to achieve passage of this critically important legislation."

Nuclear regulatory reform

The second legislative initiative that the Reagan team says is of high priority is that of reforming the nuclear licensing and regulatory pro-

Continued on page 19

Zimmer cancellation looms; CG&E mulls its options

CINCINNATI—Cincinnati Gas & Electric now admits it may have to cancel its Zimmer nuclear plant.

Accompanying the announcement that the cost of the beleaguered plant has nearly doubled—from $1.7 billion to $3.1 billion—the admission by CG&E that it may have to cancel the Zimmer plant brings the project nearer to becoming the first plant in U.S. nuclear power program history ever to be abandoned after virtually being completely built.

In March, 1983 CG&E senior vice president E. A. Borgmann declared "We firmly believe that the Zimmer plant is basically of sound construction and we are dedicated to seeing that it receives an operating license."

A total of $1.5 billion has been invested in the plant so far.

Whether it gets an operating license or not now depends on a host of factors, including whether or not CG&E will be able to convince the Nuclear Regulatory Commission to lift the stop-work order imposed last November 12 after the agency discovered serious construction and quality-assurance deficiencies.

As part of its stop-work order, the NRC set out general guidelines that CG&E, as major owner and constructor of the plant, would have to follow before construction could resume. The order called for an independent management audit of CG&E, recommendations on how management could be restructured, a review of project construction by the new management, the securing of assistance in construction by an outside consultant, and specific recommendations on how the plant could be made suitable for licensing.

Each of these steps has to be approved by the commission.

Report submitted

In August, Torrey Pines Technology submitted its report as independent management auditor, recommending a complete management restructuring from (but not including) the president on down.

According to an NRC Region III spokesman, much of this managerial restructuring had been accomplished at CG&E before the Torrey Pines report was issued. The report also recommended the formation of a company oversite committee composed of members of the board of directors. The suggestion was aimed at assuring more direct control of construction by the company.

In October, based on the Torrey Pines report, CG&E submitted to the NRC its proposed course of action, which included many of the consultant's suggestions. CG&E, in announcing submission of its plans to proceed with construction, was careful not to preclude the possibility of cancellation.

Continued on page 2

Census Bureau documents gains in home heating by electricity

WASHINGTON, D.C.—The use of electricity to heat homes in America rose sharply during the 1970s, making it the second most widely used heating fuel by 1980, a report by the Commerce Department's Census Bureau says.

In 1970, fuel oil (including kerosene) constituted slightly more than a quarter of all the primary fuels used to heat homes, while electricity was not quite 8 percent.

During the decade, the use of electricity rose 139 percent, while fuel oil fell about 30 percent, resulting in a slight percentage edge of total usage for electricity by 1980. By then, fuel oil was 18.2 percent of total energy while electricity was 18.4 percent.

Utility gas, which dropped slightly over the decade, continues to be the major source of fuel for home heating. It was used by more than 40 million households by 1980.

More than 69 million households now have central heating, the report states. Between 1960 and 1980, the number of households with some form of air conditioning increased by about 40 million, an average increase of 5,000 a day. More than half of America's housing is now air-conditioned.

Electricity also has emerged as the most popular fuel for cooking since data were first gathered in 1940. Electricity use has risen from about 40 percent in 1970 to about 51 percent in 1980. Although utility gas is still being used for cooking in about 41 percent of occupied households, it has experienced a substantial decline since 1970.

In 1940, fuel oil was used for cooking in about 1 of every 10 households, but its use as a fuel for cooking was practically nonexistent in 1980.

Finally, the Census Bureau report found that the use of wood for primary heating rose about 2 percent over the decade from 1970 to 1980, while the use of coal declined by about the same amount.

HOW HOME HEATING FUELS HAVE CHANGED

	1980 Percent	1970 Percent	1960 Percent	1950 Percent	1940 Percent
Utility Gas	53.1	55.2	43.1	26.6	11.3
Bottled, Tank, or L.P. Gas	5.6	6.0	5.1	2.3	–
Fuel Oil, Kerosene, etc.	18.2	26.0	32.4	22.6	10.0
Electricity	18.4	7.7	1.8	0.7	–
Coal or Coke	0.6	2.9	12.2	34.6	54.7
Wood	3.2	1.3	4.2	10.0	22.8
Other Fuel or None	0.9	1.0	1.3	3.2	1.2

Source: Census Bureau, U.S. Department of Commerce.

Energy policy . . .

from page 1

cess. Declaring that it is "...imperative that the United States maintain nuclear power as a viable energy option and an area of technical leadership," The National Energy Policy Plan concedes that consumers, public officials, industry and some regulators increasingly have come to doubt the ability of federal regulation to assure nuclear safety.

But the administration's 1983 legislative proposal on nuclear licensing reform notwithstanding, Reagan energy officials report that "the question of public confidence in nuclear safety is not simply a matter of federal responsibility."

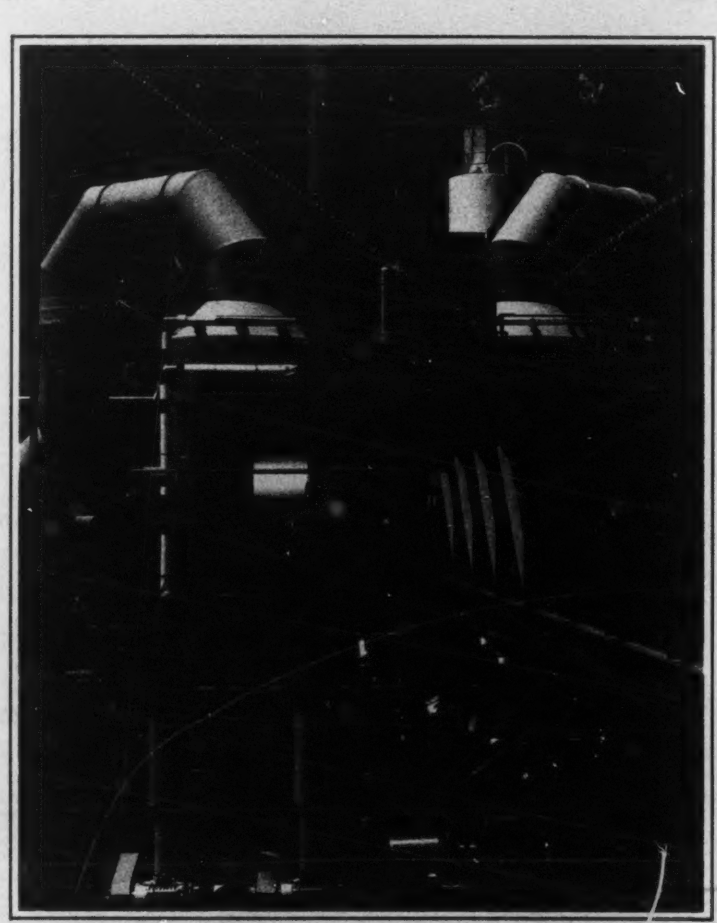
"The federal government will continue to work cooperatively with states and localities in the development of [emergency contingency] plans, and it will do so recognizing that the task of maintaining and renewing public confidence in government regulation and control of nuclear-generated electricity is shared by officials at all levels of government and must be accomplished as a matter of providing for our general welfare," the policy report reads.

Fed role

The federal government's role in this nuclear safety regulatory confidence recovery is essentially embodied in the administration's "Nuclear Licensing and Regulatory Reform Act of 1983." The bill is promoted on the basis that it would provide NRC approval of suitable sites prior to filing of construction permit applications, would authorize the use of optional standardized designs for entire plants or major subsystems, and would provide "a disciplined process for requiring equipment modifications on new and existing plants."

The bill reportedly would additionally offer an optional combined construction and operating license, and improve the public hearing process.

"Their combined effect," the administration maintains, "will provide a more rational and integrated approach to nuclear licensing, resulting in improved safety, reduced costs, and, it is hoped, renewed public confidence in the reliability of nuclear-generated electricity."



The PCB destroyer

SCA's Chicago incinerator has recently been issued an EPA permit for the incineration of liquid and solid PCB's. With this permit, SCA can now offer a complete line of PCB disposal services, including:

- EPA permitted PCB incineration
- EPA permitted PCB secure chemical landfill
- Transformer decommissioning and decontamination
- Capacitor and small transformer disposal
- PCB clean-up service
- Bulk transportation by rail or truck

For further information on SCA's PCB services, please call:

PCB ACTION LINE — 800-SCA-9999
(ILLINOIS only — 800-SCA-7210)

World Headquarters: Boston, MA, (617) 367-8300; *Major SCA Chemical Services Facilities:* Chicago, IL, (312) 660-7200; Newark, NJ, (201) 465-9100; Model City, NY, (716) 754-8231; Pinewood, SC, (803) 452-5003; Braintree, MA, (617) 849-1800; Lawrence, MA, (617) 687-2775; Fort Wayne, IN, (219) 447-5585; *SCA/Triangle Resource Industries:* Laurel, MD, (301) 953-9583; Reidsville, NC, (919) 342-6106; Greenbrier, TN, (615) 643-4511.

SCA CHEMICAL SERVICES

Inquire R.S. 6

12/12/83
C8650-4A

Volume 61, Number 12
December 1983

Electric Light & Power

THE NEWS MAGAZINE OF ELECTRIC UTILITY MANAGEMENT AND TECHNOLOGY

Senate cuts Clinch River Breeder lifeline

Don Minner
Assistant Editor

WASHINGTON, D.C.—The Senate finally pulled the plug on the gasping Clinch River Breeder Reactor project in Tennessee.

Proponents of Clinch River called the 56-40 vote to stop providing funds for the reactor "shocking" and "overwhelming." A Department of Energy spokesman said Secretary Donald Hodel was "disappointed" with the vote and that the department "would proceed with an orderly termination of the project."

Ever since the project was authorized in 1970, it has been the target of fierce opposition. Opponents said it was unneccesary and too costly. Approximately $1.7 billion has been spent on site work and estimates to complete the project have ranged from DOE's $4.1 billion to opponent estimates of more than $8 billion.

Supporters always have claimed that the breeder would help America to become more energy independent.

The project's fate rested on an alternative financing plan devised by Sen. James McClure (R.ID). The plan called for the government to appropriate $1.5 billion and for other sources to come up with $1 billion.

In mid-October, the Senate Appropriations Committee approved the plan, 18-10, but it wasn't as easy when the measure reached the Senate floor a week later.

When the floor vote reached 50 against funding on Oct. 26, Sen. Howard Baker (R.TN), the project's main sponsor, finally threw in the towel and released other senators committed to Clinch River. "The Senate has spoken," he said. "I will not prolong the debate."

Lobbying efforts by Baker kept the project alive last year by a one-vote margin. Some felt that his decision not to seek re-election to the Senate may have had an influence on the measure's defeat.

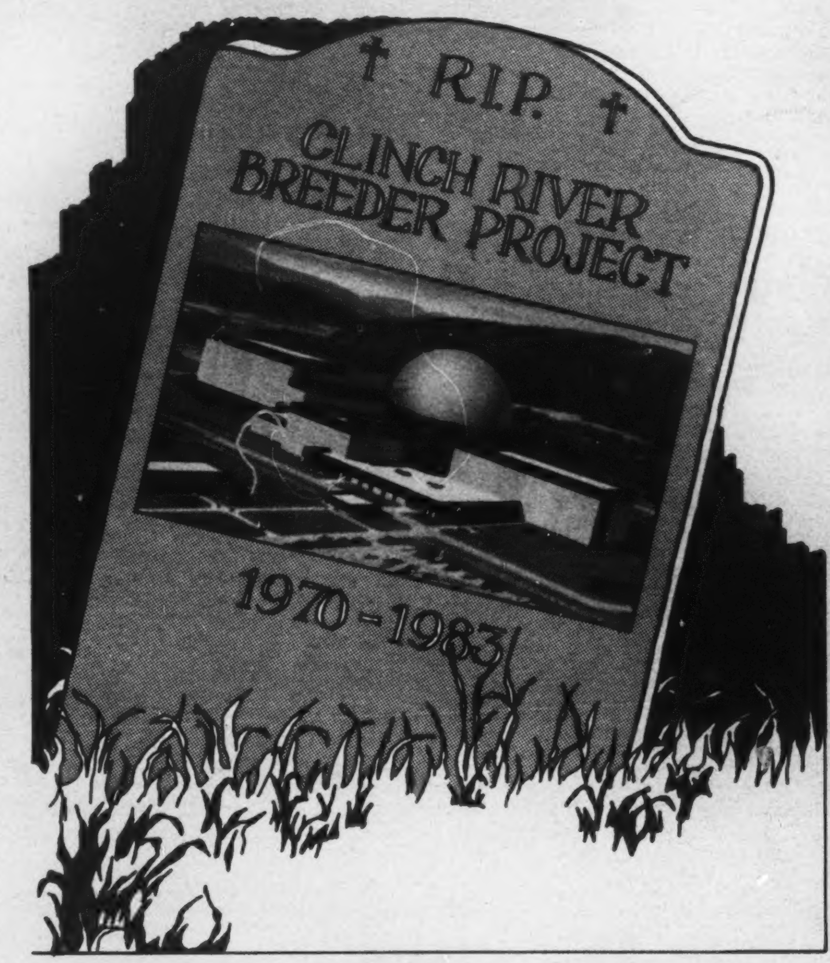
One of Clinch River's most vocal critics, Sen. Dale Bumpers (D.AR), said, "In five years, I've never had a victory this satisfying. The breeder reactor is an out-moded technology. It was never economically viable and the new financing plan was a sham."

A spokesman for Sen. Bumpers said the decision to stop funding probably killed the project forever and that it would probably not be brought up again.

Nuclear Safety Analysis Center Director A. David Rossin, a vocal and ardent supporter of Clinch River, said he was concerned about the effect the cancellation would have on future nuclear reactor orders. "If we don't see breeders in the future, we'll have very few orders for new reactors," he warned.

Rossin said there is presently enough uranium to meet the needs of operating and planned nuclear units, but that the resource is finite. If the U.S doesn't have a breeder operating or in the works, he suggested, many utility executives will find it extremely hard to commit to a nuclear plant in the future.

Continued on page 2



Marble Hill future hazy as Indiana governor seizes planning initiative

Talk of cancellation accompanies cost rises, scheduling delays

INDIANAPOLIS—After announcing scheduling delays of up to two years and cost escalations of nearly $2 billion, Public Service Indiana has gone into a holding pattern on its two-unit Marble Hill nuclear plant.

A tough cash-flow squeeze; the cutting off of a rate control plan submitted by PSI to the Indiana Public Service Commission aimed, in part, at relieving some of the company's burdensome financial pressures; and the capturing of policy initiatives by the Indiana Governor's Office has left the midwestern utility foundering in a sea of corporate uncertainty.

For the first time, government officials are raising the possibility that the entire two-unit station may be cancelled. PSI, however, continues to argue for completion. "We still want to finish both units," the company's Julie VanUtt said.

To date, some $2.2 billion has been invested in the plant. Public Service Indiana owns 83 percent of Marble Hill; Wabash Valley Power Association owns the other 17 percent. Unit 1 is about 55 percent complete; unit 2 is almost 35 percent complete.

The two-year delay in construction of the plant pushes start-up of the two units to December, 1988, and January, 1990, respectively. The estimated cost revision moves the previous estimate of $5.1 billion to $7 billion, and some see the costs rising even higher.

Governor to PSC: Hold off

As late as August, PSI had complied with a Public Service Commission order to submit a plan directed at avoiding the large rate shock that is expected when the Marble Hill units

Continued on page 3

Summer heat boosts 3rd quarter utility revenues

BARRINGTON, IL—Record-breaking summer temperatures and continued industrial output growth helped boost third quarter electric utility kilowatt-hour sales, operating revenues and earnings per share.

According to data taken from Edison Electric Institute weekly reports, kilowatt-hour output rose 9 percent in the third quarter of this year, compared to 1982.

A random sampling of 34 electric utility third quarter financial statements also revealed that many experienced marked improvements in operating revenues, electricty sales and earnings per share.

Utilities weren't the only benefactors of the improving economy. Increased consumer spending helped to increase profits in pharmaceuticals, consumer electronics and home appliances. Higher profits were also reported by the railroad, aerospace, chemical and publishing industries.

The U.S. Dept. of Commerce reported a 7.9 percent annual rise in the third quarter real gross national product, compared with a 9.4 percent rise in the previous quarter. Commercial Credit Company commented that the new figure "represents strong growth."

"The increase in third-quarter real output reflects both an increase in final sales and a swing in inventories to accumulation in the third quarter from liquidation in the second," said the Commerce Department.

Other indicators favorable

Other indicators pointed to a continuing economic recovery. The Index of Industrial Production, which measures the physical output of the manufacturing, mining and utility sectors, increased 1.5 percent in September—the tenth consecutive monthly rise.

Continental Bank said in a newsletter that "The continued strength in September confirms that a broad-based business recovery now is well-established, and, based on trends seen in previous economic recoveries,

continued on page 51

EL&P 1984 ELECTRIC INDUSTRY OUTLOOK REPORT

1984 to be year of financial rebuilding, reduced construction spending for utilities

Robert A. Lincicome
EL&P Editor-in-Chief

Barring unforeseen difficulties, 1984 should be a good year for utilities. Good, but not great, as heavy generation construction programs (especially nuclear programs) continue to wind down, internal generation of funds improves and external requirements decrease, earnings increase and regulatory problems diminish.

According to *EL&P's* survey of utility organizations, security firms, industry associations and government agencies, many of the actions and movements of this year can be expected to continue in 1984. However, as a number of contacts point out, 1984 is an election year and that means anything could happen. However, the betting seems to be that the fact of the election may serve to remove attention from utilities as legislators focus pre-election efforts on more pressing, popular causes.

Construction spending to decline

Projections based on *EL&P's* survey of electric utility organizations indicate that construction spending by electric utility organizations should total $37-billion in 1984. This represents a decrease of $2.6-billion, or 6.7 percent, from our estimates of total electric utility industry capital spending in 1983.

The decline is especially noticeable for generation spending. Utilities reported that capital spending for generation will total about $23-billion, a slide of some $5.6-billion from this year and even $2.5 billion under generation construction in 1982.

There is one *caveat* here, however, and that is that several utilities currently involved in completing major multi-unit nuclear plants provided data for their generation construction aside from the nuclear program. In other words, nuclear utilities could be forced to spend substantial amounts beyond their current plans, like it or not, and the totals projected by *EL&P* could be understated by several hundred million dollars. The odds are good, however, that the majority of the additional spending will go for highly labor-intensive operations and for debt service, rather than for hardware or apparatus.

T/D spending to climb

Spending for transmission, distribution and substation additions should be up in 1984, according to *EL&P's* survey. If utilities live up to their current plans, capital spending in these areas should total $12.6-billion, ahead a hearty $2-billion from 1983 spending.

Largest amount would be devoted to distribution, where utilites indicated that some $6.3-billion will be spent.

Transmission spending should total $3.4-billion, according to the survey.

Spending for substations, rated for both transmission and distribution, is projected to reach $2.8-billion.

Actually, spending estimates for both transmission and distribution are somewhat overstated and spending estimates for substations is somewhat understated because some utilities lumped substation spending into their plans for transmission and distribution construction, rather than stating them separately as requested.

As indicated in the table below, the greatest construction activity will take place in the Southeast (SERC) and in the Far West (WSCC), where planned total capital spending is estimated to be $9.5-billion and $6.4-billion respectively.

EEI survey results

Bruce Humphrey, director of energy modeling and economic research for the Edison Electric Institute, says the EEI doesn't "do forecasting as such, but we do explore alternative scenarios." The most popular scenario for energy sales, he said, is for kilowatthour use to increase at the same rate as the economy. He noted that electric-intensive industry recovered slower in 1983 than the economy as a whole, but expressed a belief that faster imrovement will be recorded in 1984. With the Gross National Product expected to grow at a rate of 4- to 5-percent annually in 1984, kWh sales may be expected to increase similarly.

EEI has made a survey of investor-owned electric utility construction spending and suggests a total of $36.7-billion for 1983 and $34.6-billion in 1984, declining steadily to $27.8-billion in 1987.

Humphrey said the declining level reflects the winding down of power plant projects. A turnaround is not expected until 1990 or later.

Improved performance expected

While other industry analysts disagree on whether construction expenditures have peaked or if they will peak this year or next, the picture they agree upon is one that is getting brighter. The trend, they agree, is favorable; the financial condition of utilities is improving markedly.

"The industry is starting to get healthy," notes Mark Luftig, head of the utility analysis division at Solomon Brothers.

For the 100 companies that Solomon Brothers monitors, construction expenditures will peak this year. Solomon Brothers data indicates that these companies will spend $31.3-billion on construction in 1983, declining to $30.1-billion in 1984 and $27.7-billion in 1985.

As construction expenditures decline, more plants are completed and are put into the rate base. Moving plant capital expenditures into the rate base transfers Allowances for Funds Used During Construction (AFUDC) into a cash-earning status, which contributes to utility earnings. AFUDC is the aggregated non-cash return a utility accrues on its capital investment. Regulatory commissions allow AFUDC to be converted into "cash" from customers only after the facilities are completed (or are largely completed, in some states) and become "used and useful."

According to Solomon Brothers' top 100 electric utilities' statistics, about 43.5 percent of the 1983 construction expenditures (or about $13.6-billion) will be financed with internally generated funds. By 1985, says Luftig, this figure will rise to about 67.2 percent of total construction spending or about $18.6-billion.

1984 CAPITAL SPENDING ($1000s BY N.E.R.C. REGION)

	Generation	Substations[1]	Transmission[2]	Distribution[2]	Other	Total
NPCC	1,555,525	151,588	153,837	682,958	85,401	2,629,309
MAAC	1,584,530	512,767	170,815	466,215	144,645	2,858,972
ECAR	3,962,093	236,397	474,956	535,977	265,681	5,475,104
SERC	6,146,171	369,149	1,123,504	1,519,251	361,753	9,519,828
MAIN	2,151,678	76,146	71,738	568,062	143,005	3,010,629
SPP	2,528,516	195,794	493,530	570,596	155,836	3,944,272
ERCOT	1,706,049	168,927	223,180	370,574	189,048	2,657,778
MAPP	127,566	103,461	57,351	168,630	29,058	486,066
WSCC	2,955,891	1,023,095	647,279	1,475,798	281,433	6,383,496
Total	22,698,019	2,837,324	3,416,190	6,358,061	1,655,960	36,965,854

Source: EL&P Survey

1. Includes both transmission and distribution substations, where given as a separate category. Actually understated because a number of respondents reported substation investments were included in transmission and distribution programs.
2. Overstated because some companies included substation investments in transmission and distribution construction programs.

The increasing portion of construction funds generated internally by utilities means that less new money will be required and raised in the debt market.

Duff & Phelps analyst Thomas P. Halligan envisions electric utility construction expenditures to increase through 1984, then decline at least through 1987. For Duff & Phelps, 1984 will be the peak year in construction expenditures, and, says Halligan, will be higher than calculated earlier because a number of power plants expected to be completed in '83 will not be completed and licensed until 1984 and later.

Duff & Phelps estimates that 1983 construction expenditures will be $36.7-billion, rising to $37-billion in 1984. About $18.3 billion, or roughly half the 1983 expenditures will be from internally generated funds. Next year, about $22.5-billion (or 60 percent) of the 1984 industry construction budget will be internally generated.

Acid rain to force spending

Countering the progress in decreasing construction spending in the next few years is an anticipated, but as yet unquantified, increase in the construction of pollution control systems. Analysts agree that some form of acid rain legislation may be forthcoming in the second session of the current Congress, beginning next January. What is hard to predict, they say, is the form that legislation may take.

Figures ranging from $6-billion to as much as $23-billion are offered as educated guesses of the amounts that *might* be required for pollution control over the next few years.

None of the industry organizations contacted by *EL&P* wants to be accused of being anti-environment, but raise strong questions about how much is actually known about acid rain, its real causes and effects. The National Rural Electric Cooperatives Association follows the reasoning of other major industry organizations, questioning the so-called "evidence" and calling for more research as a step to better understanding of the problem. However, a spokesman suggested that if it is demonstrated that Midwest utilities, including generation and transmission cooperatives, are responsible for the acid rain problems plaguing the Northeastern U.S. and Canada, then the utilities involved will take action.

Alex Radin, peppery executive director of the American Public Power Association, says he sees no legislative action on acid rain in 1983, but believes there will be action in Congress next year. He calls for a nationwide emissions tax, to be applied to all sources of emission.

Federal deficits and interest rates

Uncertainties over the magnitudes and effects of large budget deficits continues to confound most analysts. Duff & Phelps' Halligan comments that deficits of the order of $200-billion are not, of themselves, necessarily disastrous, provided that they remain historically proportionate to Gross National Product. But if the economy is sluggish, or turns downward, such large deficits could have enormously harmful impacts.

Mark Luftig of Solomon Brothers notes that, given the apparent disinclination of Congress to either cut federal expenditures or to raise taxes in an election year, the Federal Reserve System may be forced to tighten the money supply. Such an action could result in higher interest rates, at least in the short term.

Relatively high interest rates are one reason why "interest rate swaps" are likely to remain attractive. Interest rate swaps are financial schemes where a borrower in the U.S. will raise money at floating interest rates, while a counterpart in Europe raises money at fixed rates. The payment streams then are traded, although not the principal obligations themselves. The advantage to the U.S. borrower is that it can obtain funds at a lower, fixed rate of interest.

Luftig suggests that other innovative financing techniques will continue to be employed although, in contrast to creative financing a few years ago that were used in order to gain access to otherwise unobtainable funds, creative financing today is used more to get around high domestic interest rates.

Even if interest rates remain largely where they are today, Luftig says, it appears likely that there will be considerable debt refunding over the next few years. There is about $15-billion of maturing utility debt coming due. In addition, even at interest rate levels of about 13 percent, Luftig

Continued on next page

1984 outlook . . . from preceeding page

suggests that it will be economical to refund as much as $25-billion of nonmaturing debt as well. This would call for rolling over debt incurred about 5-years ago, when interest rates were on the order of 15- to 16-percent.

In the event that interest rates drop a few points, perhaps to the 10-percent level, Luftig says that another $20-billion of debt could be refunded, bringing total potential refunding requirements to nearly $60-billion by 1987.

At the same time, the bond market is seeking higher yields and investors don't appear to be so discriminating about quality, Luftig observed.

1984 CAPACITY ADDITIONS BY N.E.R.C. REGIONS (MW)

	1983 Capacity	1984 Capacity	1984 Additions	1984 % Change
NPCC	51,690	52,850	1,160	2.24
MAAC	47,480	48,800	1,320	2.78
ECAR	92,500	96,120	3,620	3.91
SERC	125,650	128,800	3,150	2.51
MAIN	43,760	45,190	1,430	3.27
SPP	60,550	62,310	1,760	2.91
ERCOT	43,860	45,400	1,540	3.51
MAPP	28,490	28,440	-50	-0.18
WSCC	107,740	109,920	2,180	2.02
	601,720	617,830	16,110	2.68

Source: North American Electric Reliability Council Statistics and EL&P Projections.

Finally, there appears to be some general agreement that electric utility enthusiasm for dividend reinvestment is dwindling. While there are a number of companies that will continue to issue shares of common with 5 percent discounts, many others are dropping the practice. Some will phase out the use of this method for selling stock because their equity ratios are getting up to where companies want them.

Margins adequate

As construction expenditures peak this year or next, aand as more generating plants are completed and go into service, reserve margins should remain strong. According to the Department of Energy, the healthy reserve margin is expected to continue. In the longer term, out about 1990, for example, there are likely to be capacity shortages unless there is a resurgence of construction activity.

In the mid-term, DOE estimates that peak demand will increase at about 4-percent per year through 1985 as the economic recovery builds to full-steam. After this, DOE sees peak demand increasing at about 3 percent annually during the period from 1985 through 1990. Through 1987 DOE expects reserve margins to remain above 35 percent nationally.

Although DOE normally confines itself to longer range forecasts, Jeffery Skeer of DOE's Office of Policy, PLanning and Analysis, provided *EL&P* with the near-term numbers, noting that these were consistent with the 1990 estimates DOE released as part of its June 1983 report of the Electricity Policy Project (see *EL&P*, August 1983, page 1). The report, called "The Future of Electric Power in America: Economic Supply for Economic Growth," stated that current institutional, regulatory and financial constraints were imposing powerful disincentives on electric utilities to invest in new generating capacity. Unless these disincentives can be overcome, the report said, they would lead to a measurable lessening of electric service reliability by 1990 and inadequate generation capacity a few years later.

According to DOE's "1982 Annual Energy Outlook," which was released to the public in mid-1983, 14,107 MW of new capacity will be added this year by December 31. An added 18,118 MW is projected to go into service in 1984. Over the period 1984-1987, DOE estimates that an average of 18,709 MW will be added in each of the four years, resulting in some 74,837 MW of new capacity going into service by the end of 1987.

In its electricity policy report, DOE said that a 3-percent load growth through the year 2000 translates into a need for an additional 438 GW of capacity by the end of the century. This would mean that average annual capacity additions of about 23,053 MW per year would be needed over the 19 years from 1981.

The implications of these numbers are that, given DOE assumptions, annual capacity additions already are deficient by about 19 percent, and these calculations are based on plants that were started before the now dominant reluctance of electric utility managements to commit new funds to new generation.

Generally running counter to DOE's assumptions, however, are developments that could mitigate against implied generation deficiencies. Included are growing awareness that electricity demand and national economic growth may *not* be coupled, increasing employment of load management and conservation techniques, use of cogeneration and installation of small power production facilities by non-utility entrepreneurs.

APPA's Radin agrees that determining the need for power in the future is an overriding issue. In an earlier presentation to an Americans for Energy Independence Conference in Washington, Radin suggested that under a moderate-growth scenario (3 percent GNP growth and 2 percent annual increase in the price of electricity) only 647 GW would be required, instead of the North American Electric Reliability Council's 'projected' 710 MW. He pointed out that post-1981 additions of 152 GW to reach the NERC figure would provide a reserve margin of 31 percent in 1990 and average margins of 34 percent over the period from 1982 through 1989, but that only 75 GW would be required under the moderate growth scenario. "Given the magnitude of future capacity requirements and the high cost of building power plants, conservation and a variety of energy sources should be looked at first as a means to meet the nation's energy requirements," he commented.

Radin said he believes there will be continued interest in small, conventional power plants when new capacity is needed. He also suggested that utilities will devote more effort to upgrading and refurbishing older existing power plants. Such efforts, he said, are very cost-effective and involve fewer regulatory problems than new plants. He said he believes a resurgence of nuclear power interest is at least 10 years down the road.

Dim nuclear future

As reported elsewhere in this issue (see article reporting on the proceedings of the Atomic Industrial Forum meeting, page 3), the outlook for the nuclear industry seems to be a hang-on-and-pray-a-lot situation, despite what AIF Chairman Wallace Behnke, Commonwealth Edison vice chairman, said in prepared remarks and in a press conference. Behnke focused his appraisal of progress largely on developments begun earlier, but continuing, and glossed over some of the larger problems before the industry, such as the general anti-nuclear mood of the public, the debacles of the Washington Public Power Supply System, the Zimmer plant of Cincinnati Gas & Electric, minimal progress on the cleanup of TMI-2 and the probable rate shock imposed by large nuclear plants, including those of Behnke's own company, and the continuing morass of Nuclear Regulatory Commission retrofit and licensing activity.

Observers generally agreed that Behnke's enthusiasm did not appear to be warranted by the general dark picture portrayed by suppliers of nuclear systems and many of their utility customers.

Regulatory outlook

One of the current points of controversy, around which swirls both a utility's need for adequate return on its construction investment and the social benefit of husbanding excess capacity to meet the future needs of its customers, is the issue of marketing.

Electric utilities increasingly are turning to more aggressive marketing activities in an effort to promote kWh sales, especially as they contribute to improved load factor. They do this against a backdrop of growing regulatory and social awareness of the need for and effects of conservation. It seems clear that regulatory agencies will be called upon to find a balance between these two concepts in the years ahead.

Even though the president of the National Association of Regulatory Utility Commissioners does not believe that conservation and the marketing of electricity are necessarily mutually exclusive, he does caution that simultaneous promotion of the two concepts will have to be done "artfully."

Larry Wallace says that 1984 will be a year of "planning, thinking and organizing" marketing strategies, and he believes it will be well into 1985 before anyone is likely to see well-thoughtout approaches by the industry as a whole. Broadly defining conservation as "the efficient use of electricity," the retiring chairman of the Indiana Public Service Commission notes that the coalescence of marketing and conservation occurs when electric utilities promote the use of idle capacity for new and more efficient applications. Its basis is embodied in Wallace's notion of "special rates for special processes."

NARUC assistant general counsel Charles Gray observes, however, that there could be some rough spots along the way. He points out the potential for anti-competitive claims small business groups as behemouth utilities begin to move into marketing specific appliances, such as the heat pump. Noting that utilities have some decided promotional advantages, such as updated customer listings, potential promotion through bill inserts, access to special financing, Gray suggests that utilities may take the lion's share of such new sales, at the sacrifice of its trade allies. He does admit, however, that the movement of utilities into such areas could also create new markets that are not present today. "Nevertheless, there could be a lot of pressure on regulators to decide these anti-competitive claims."

Another major regulatory concern involves equitable treatment for low-income groups that have difficulty paying their electric bills. Currently there are a variety of special programs aimed at relieving the acute problems of this growing group. One problem is targeting the truly needy, distinguishing them from those with the ability to pay but without the willingness to do so.

More generally, the NARUC executives think there may be a stabilization of regulation with respect to financing the industry as power plants are completed and go into rate bases. Observers point out that there still will be vigorous debates in some regions as nuclear utilities and regulatory agencies battle over how to put massive amounts of new plant investments into the rate base while muting the rate shock that surely will follow.

But the breakup of AT&T and the de-regulation (or re-regulation) of natural gas seem likely to draw much of the attention and efforts of regulators. Although some observers believe that these developments could push electric utility regulation "into the back seat," others suggest that from now on "the front seat will just be more crowded."

But, then, 1984 is an election year, with a number of governors coming up for reelection, and that means crazy things can happen.

Suppliers see slight rebound

Sales of power equipment, after a small estimated 0.4 percent decline in 1983, are expected to move upward again in 1984. The National Electrical Manufaturers Association (NEMA) is hopeful of a 2.7 percent improvement in 1984. To keep this in perspective, however, remember that the projected 6.3 percent average growth rate for sales of all electrical equipment is expected to run behind the growth rate of the economy as a whole. And more importantly, it must be noted that of NEMA's eight product groupings, power equipment is projected to have the lowest growth rate.

These projections were released in conjunction with NEMA's 57th Annual Meeting in Washington. The association's power equipment group is composed of manufacturers of most of the products used by electric utilities, including steam turbine-generators, power transformers, switchgear, circuit breakers, surge arresters and protective equipment, power capacitors, insulators, connectors, line and substation hardware. Also included are tapered steel structures, poles and the like. NEMA did not provide dollar figures.

Cast your ballot for the 1984

ELECTRIC INDUSTRY MAN OF THE YEAR

See the January issue of Electric Light & Power

TVA quantifies value of burning physically cleaned coal or plant operating, maintenance, FGD costs

Washed coal can reduce boiler outages, maintenance costs, and flue-gas desulfurization costs, according to recent reports from the Tennessee Valley Authority.

The TVA work, largely sponsored by the U.S. Dept. of Energy and the Environmental Protection Agency, seeks to justify the added costs of conventional coal cleaning over purchase of raw coal by quantifying the benefits. In recent years use of washed coal has declined as utilities sought to reduce fuel costs.

A study done by consultants Battelle-Columbus and Hoffman-Holt examined boiler performance data and coal quality at 60 TVA generating units during the years 1962-1980. According to a paper given at the recent Joint Power Generating Conference, the study shows that lower levels of ash, moisture, and sulfur in the incoming coal result in higher boiler efficiency, fewer forced outages, and reduced maintenance costs. Using a model derived from the study researchers predicted savings equivalent to from $1.50 to $2.00 a ton of coal from using clean coal at certain power plants.

The examination of boiler efficiency showed that, while it was difficult to separate the effects of boiler age and coal quality, large changes in coal ash and moisture can have a significant effect. "For example," says the JPGC paper, "increasing coal ash from 8 to 20 percent and moisture from 6 to 10 percent will reduce boiler efficiency by 0.66 percent."

Availability improved

The study also showed a relationship between ash and sulfur levels and boiler outage hours. Over the range of coal ash in TVA's coal, 12 to 24 percent, the relationship showed that increasing ash levels were associated with as much as 360 outage hours per year, as shown in Table 2. Sulfur levels, ranging from 1 to 5 percent, could account for as much as 870 hours. Together, the two coal contaminants account for 1400 unplanned outage hours.

Using the values shown in the table, including the replacement power costs, the researchers compared a change from a coal with 20 percent ash and 4 percent sulfur to a coal with 10 percent ash and 1 percent sulfur. The value of the lower coal in terms of reduced replacement power alone was calculated to be $1.64 per ton of coal for a 100-MW base-loaded unit.

Reduced ash effect studied

Effect of reduced ash and sulfur on the cost of maintaining the pulverizers, boilers, and other coal-related equipment was also studied. Results are shown in Table 1. An "extreme" change in coal quality, from 20 percent ash and 4 percent sulfur to 12 percent and 1 percent, would produce maintenance savings equal to $0.36 per ton of coal.

A summary of the kinds of savings that could be expected at typical plants for the areas covered in the study is shown in Table 3. The total saving in this example, going from 18 percent ash and 2.5 percent sulfur to 12 and 1.5 percent, is a saving of $1.57 per ton of coal.

FGD cost reduction

Another related study of the effect of coal quality on FGD costs was reported at the recent EPA/EPRI symposium on FGD in New Orleans. Using the coal-cleaning model developed by Battelle Columbus as a starting point a new model was developed that shows potentially large FGD costs savings through use of coal cleaning.

The basic conclusion, reported TVA engineer Charles Wright, is that combining coal cleaning with flue-gas desulfurization can sometimes produce lower net costs than use of tail-end flue-gas cleaning alone. For an extreme case such as high sulfur Illinois 6 coal the combination can reduce costs 15 to 20 percent, he reported.

Wright warned that in some cases coal cleaning can lead to an increase in particulate collection costs. Coal cleaning will reduce sulfur dioxide in the flue gas and increase fly ash resistivity, reducing the effectiveness of electrostatic precipitators.

Wright said that the benefits of coal cleaning are site-specific but he added that for the cases studied with the TVA model the net effect on levelized annual cost of power reduction ranged from an increase of 0.5 percent to a decrease of 22.6 percent from using coal cleaning and FGD.

(The papers used as sources for this data were "Examining relationships between coal characteristics and the performance of TVA boiler plants: summary," ASME, 1983 JPGC, by Richard Barrett, Elmer Holt, Gregory Mack, and Robert Frank; and "Computer economics of physical coal cleaning and flue gas desulfurization," 1983 EPA/EPRI symposium on FGD, by Charles Wright, Terry Tarkington, and James Kilgroe.)

EFFECT OF CHANGING COAL CHARACTERISTICS ON MAINTENANCE COSTS
(1965 MW plant, 80 percent annual load)

a. Effect of ash (sulfur = 3.5 percent)

Ash, percent	Maintenance Cost, Selected Coal-Related Equipment, 1978 dollars
12	1,579,000
13.5	1,623,000
18	1,812,000
20	2,148,000
24	2,546,000

b. Effect of sulfur (ash = 13.5 percent)

Sulfur, percent	Maintenance Cost, Selected Coal-Related Equipment, 1978 dollars
1.0	1,383,000
2.0	1,484,000
3.0	1,575,000
3.5	1,623,000
4.0	1,673,000
5.0	1,794,000

Table 1. Effect on maintenance costs.

EFFECT OF CHANGING VALUES FOR VARIABLES ON UNPLANNED OUTAGE HOURS

a. Effect of ash (Sulfur = 3.5 percent, age = 20 years)

Ash, percent	Forced Outage Hours	Outage Hours Compared to Baseline	Incremental Cost of Replacement Power for 100 MW Loss, 1979 dollars
12.0	773	-38	(25,918)
13.5	811	0	0
16.0	879	+68	46,376
20.0	999	+188	128,216
24.0	1136	+325	221,650

b. Effect of sulfur (Ash = 13.5 percent, age = 20 years)

Sulfur, percent	Forced Outage Hours	Outage Hours Compared to Baseline	Incremental Cost of Replacement Power for 100 MW Loss, 1979 dollars
1.0	390	-421	(287,122)
2.0	523	-288	(196,416)
3.0	701	-110	(75,020)
3.5	811	0	0
4.0	940	+129	87,978
5.0	1259	+448	305,536

c. Effect of boiler age (Ash = 13.5 percent, sulfur = 3.5 percent)

Boiler Age, years	Forced Outage Hours
0	176
10	292
20	811
30	1453
40	1708

Table 2. Effect of coal quality on outage hours.

IMPACT OF COAL QUALITY ON A 1965 MW PLANT[a]—SYSTEM MODEL[b]

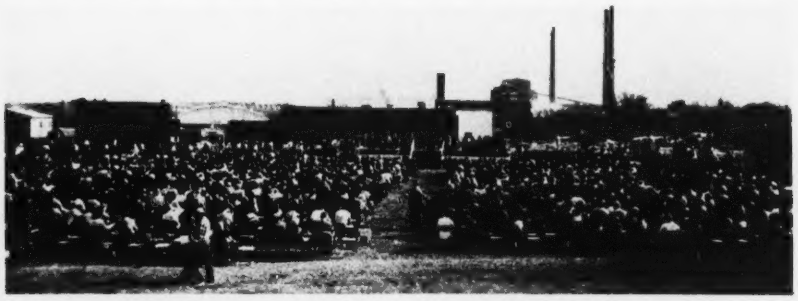
	Coal A	Coal B	Savings
Ash, percent	18	12	
Sulfur, percent	2.5	1.5	
Moisture, percent	6	6	
Heating Value, Btu/lb	11,824	12,800	
Coal Fired, 10^6 ton/yr	5.821	5.426	
Efficiency, 10^6 dollars	—	—	0.307
Efficiency, $/ton	—	—	0.05
Unplanned Outage Hours, hr	725/1225	468/795	
Lost Generation, 10^6 MW hr	1.592	1.220	
Incremental Cost of Replacement Power, 10^6 dollars	9.951	6.124	3.827
$/ton	1.71	1.13	0.58
Maintenance Costs for Coal-Related Equipment, 10^6 dollars	10.180	4.414	5.766
$/ton	1.75	0.81	0.94
Total Savings, 10^6 dollars			9.900
Total Savings, $/ton			1.57

(a) Using Widows Creek plant data for age, constants in availability and maintenance cost models, and cost of replacement power; and using 80 percent annual load factor, 10,000 Btu/kW hr heat rate, and $20/ton coal cost.

(b) Using system-wide models for relationships.

Table 3. Net effect of coal ash and sulfur levels on costs.

MPC's Colstrip 3 & 4 dedicated



More than 3,500 persons attended the dedication ceremonies of Montana Power Company's coal-fired Colstrip Units 3 and 4 in October. The 700,000-kW plants are the largest single construction project in Montana history. Finished at a cost of $1.8 billion, the Colstrip units are partially owned by MPC, Puget Sound Power & Light, Portland General Electric Co., Washington Water Power Co. and Pacific Power & Light.

BEST COPY AVAILABLE

Business optimism at highest level in four years, says D&B

NEW YORK—Business optimism among the nation's executives has reached its highest level since the second quarter of 1979, according to a recent Dun & Bradstreet Corp. survey of business expectations.

D&B reports that this is the third straight quarter that optimism about sales and profits has improved. More than 1,470 business leaders were interviewed for the latest survey.

"Durable goods manufacturers reported the greatest increase in optimism, indicating that the recovery is indeed strengthening through all sectors of the economy," said D&B corporate economist and chief statistician Joseph W. Duncan.

The overall Sales Optimism Index (the percentage of executives expecting sales and profits increases minus the percentage expecting decreases) rose four points to 72, said D&B. This latest increase follows increases of 13 points for third quarter expectations and 18 points for the second quarter.

In terms of industry sectors, durable goods manufacturers expressed the greatest change in optimism with a seven point index increase to 65. D&B said the outlook among both non-durable goods manufacturers and retailers improved by three points, to 74 and 82 respectively.

Optimism declined eight points among wholesalers. Almost 18 percent of wholesalers forsee a dip in sales in the fourth quarter.

New orders expected

D&B survey results showed that the percentage of new manufacturers expecting an increase in new orders edged closer to 75 percent.

The Profits Optimism Index for all sectors climbed three points to 62, the brightest outlook since the second quarter of 1979. Durable goods manufacturers registered the greatest gain in profits optimism with a six point increase. D&B said wholesalers also expect bottom line improvements in the fourth quarter, despite their expectations for reduced sales.

The survey results point to an improving employment outlook. For the fourth quarter of 1983, 28 percent of the executives surveyed said they expect to add to their payrolls, the largest percentage in this sector since 1976. About 36 percent of the durable goods manufacturers said they expected to increase their hiring.

And 26 percent of the retailers said they expected to add to their payrolls. Only wholesalers indicated plans to reduce employment levels.

C&NW gets interest in Wyoming line

CHICAGO—Chicago & North Western Transportation Company finally has succeeded in obtaining a half-interest in an 103-mile coal line to Wyoming's Powder River Basin at a cost of $76.2 million.

The Burlington Northern Railroad said it dropped its request for a U.S. Supreme Court review of its litigation asking to overturn a 1982 Interstate Commerce Commission decision directing that C&NW be sold the half-interest in the line.

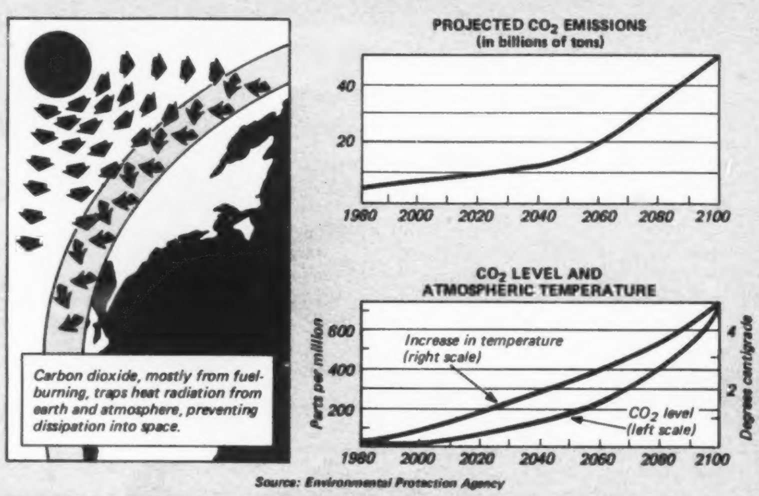
Both railroads received permission from the ICC in 1976 to build the line to the Powder River Basin. However, C&NW couldn't come up with its share of the construction money in 1979 and the BN took over the line.

C&NW eventually sought to get back in the project, which resulted in last year's ICC decision.

A Burlington Northern spokesman said only that it was "a management decision" to drop the litigation.

Greenhouse . . . from page 9

ATMOSPHERIC CARBON DIOXIDE AND THE "GREENHOUSE EFFECT"
Based on most likely (mid-range) scenario



Source: Environmental Protection Agency

decreases in precipitation and associated runoff could "severely affect" the Texas Gulf, Rio Grande, upper and lower Colorado River regions, California and other western areas. The report warned that much of the irrigated farmland in these areas "might have to be abandoned unless water could be imported from other regions with more abundant supplies."

Sea level rising

The National Research Council committee predicts that the sea level may rise two ft over the next century, compared to its current rate of four to eight inches per century, an increase of up to 667 percent.

Although the committee's findings pointed to greater study before taking any action to deal with the greenhouse effect, the EPA report warned that a "soberness and sense of urgency should underlie our response to a greenhouse warming."

Authors Stephen Seidel and Dale Keyes, of the National Research Council, also warned that "our findings support the conclusion that a global greenhouse warming is neither trivial nor just a long-range problem."

Fossil fuel ban no help

Both groups seem to agree that a ban on the use of fossil fuels would not help diminish the greenhouse effect.

Said the National Research Council, "By itself, shifting the fuel mix within fossil fuels is highly unlikely to achieve a reduction of CO_2 concentrations by more than a few parts per million by the year 2100, even if accomplished globally."

In its report, the EPA said a total fossil-fuel ban would only delay the warming effect a few years.

3rd quarter performance . . . from page 1

suggests further substantial gains in the year ahead."

For electric utilities, the unusually hot summer coupled with some recovery in industrial sales meant healthy third quarter gains.

Operating revenues for the 34 electric utilities surveyed by *EL&P* rose 9.3 percent in the third quarter, compared to the same period in 1982.

Utilities in the depressed North Central region, such as American Electric Power, Ohio Edison and Detroit Edison, all watched industrial sales and earnings per share rise in the third quarter.

AEP earnings per share skyrocketed 87.9 percent to $.62, while operating revenues increased 11.9 percent in the third quarter. W.S. White, Jr., AEP chairman, attributed the numbers to the hot summer and an improvement in industrial sales and sales to other utilities.

Detroit Edison said major increases in sales to the steel and automotive industries and their related suppliers resulted in a 12.1 percent increase in third quarter industrial sales and a total kilowatt-hour sales increase of 13.7 percent. Operating revenues jumped 19.9 percent and earnings per share rose 18 percent to $.72 a share in the quarter ending September 30.

Even Ohio Edison, which has been extremely hard hit by industry closings and slowdowns, saw good signs in the third quarter. A growth in the automotive sector helped industrial sales of electricity rise 15.9 percent. Commercial sales increased 9.7 percent and residential sales increased 11.1 percent.

The Ohio utility cited "continued improvement in the local economy and unusually hot, humid weather, which increased air conditioning use" as the main reasons for the pick-up in kilowatt-hour sales. OE reported a 23.4 percent increase in earnings per share for the third quarter and a 3.2 percent rise in operating revenues.

But some utilities were not as fortunate. Pennsylvania Power & Light earnings per share fell 9.5 percent to $.67 a share, while third quarter operating revenues nudged ahead 0.2 percent. PP&L placed the blame on the Pennsylvania Public Utilities Commission's recent decision disallowing a return on 12.6 percent of the utility's investment in generating plants.

Although operating revenues rose 17.4 percent, earnings per share dropped 2.0 percent at Minnesota Power. Jack F. Rowe, chairman and chief executive, said the "essentially flat earnings" were due to prolonged production cutbacks within Minnesota's taconite mining industry.

Prolonged heat waves across the country this summer were the major contributors to the overall improvements in electric utility health.

Con Ed, IP&L and Iowa Resources, were among the other utilities that cited weather as the reason for the improved third quarter.

3RD QUARTER STATISTICS

Utility	'83 EPS	% Change	'83 Rev (000)	% Change
American Electric Power	$.62	+87.9	1,134,000	+11.9
Arizona Public Service	$1.22	-1.6	298,000	-3.0
Baltimore Gas & Electric	$2.06	+38.3	428,780	+7.9
Carolina Power & Light	$.80	+5.3	448,720	+11.5
Central & Southwest	$1.22	+7.0	826,445	+6.5
Central Hudson Gas & Electric	$.94	+4.4	94,000	+9.0
Central Illinois Public Service	$1.19	+101.7	211,830	+63.6
Central Louisiana Electric	$1.00	+23.5	95,400	+8.8
Consolidated Edison	$1.88	+43.5	1,628,117	+18.1
Detroit Edison	$.72	+18.0	656,377	+19.9
Dominion Resources	$.32	+10.1	216,700	+20.3
Eastern Utilities Associates	$.79	+41.1	73,015	+7.4
Florida Power & Light	$2.14	+9.2	993,310	+6.6
Florida Progress	$.94	+22.1	390,828	+17.8
Hawaii Electric Industries	$1.03	+41.1	155,886	-13.6
Houston Industries	$1.61	-2.4	1,219,754	-1.7
Indianapolis Power & Light	$1.44	+34.6	121,152	+13.6
Iowa Resources	$1.73	+36.2	106,005	+15.9
Long Island Lighting Co.	$.89	+9.9	479,038	+16.0
Minnesota Power	$.98	-2.0	95,593	+17.4
Montana-Dakota Utilities	$.27	-20.6	51,881	-17.7
Montana Power	$.69	+13.1	69,286	+2.4
Niagara Mohawk Power	$.52	+4.0	662,707	+10.1
Northern States Power	$1.50	+14.5	416,900	+17.3
Ohio Edison	$.58	+23.4	386,400	+3.2
Orange & Rockland Utilities	$1.07	+20.2	124,565	+14.4
Pennsylvania Power & Light	$.67	-9.5	285,151	+.2
Philadelphia Electric	$.78	+6.8	868,258	+1.0
Potomac Electric Power	$1.31	1.3	405,511	+14.5
Public Service of New Mexico	$1.03	+6.2	107,227	-9.6
Rochester Gas & Electric	$.79	-19.1	151,838	+5.2
Texas Utilities	$1.56	+.6	1,141,912	+6.1
Utah Power & Light	$.58	-1.7	225,450	+11.8
Wisconsin Power & Light	$1.19	+35.2	132,900	+21.3
TOTAL			14,402,936	+9.3

BEST COPY AVAILABLE

1/12/84
C8650-4B

09135 1984293 W 2 302
SUITE 800 COPY # 2
STATISTICAL REFERENCE IND
CONGRESSIONAL INFO SVC D
4520 EAST-WEST HWY STE 800
BETHESDA MD 20814

Volume 63, Number 1
January 1984

Electric Light & Power

THE NEWS MAGAZINE OF ELECTRIC UTILITY MANAGEMENT AND TECHNOLOGY

Electric utilities prepare for acid rain action from EPA

Much of the pressure for acid rain regulations in the U.S. is coming from Canada where political leaders are calling for action to protect the country's lakes and forests from what they say is U.S.-originated acid rain. Special report on page 8 outlines what utilities can expect in 1984.

LP&L confronts technical, QA issues as Waterford-3 is readied for fueling

Investigative series by newspaper spurs NRC inquiry

CHICAGO—Louisiana Power & Light has been asked to publicly document that its Waterford-3 nuclear plant has been constructed safely and conforms to accepted quality assurance standards.

Even as the plant is being readied for initial fuel loading and low-power testing, a controversy has arisen over whether there are technical and quality control deficiencies in construction.

The issue came up at a luncheon gathering of security analysts in this midwestern city. Floyd W. Lewis, chairman and president of Middle South Utilities, the holding company of which Louisiana Power & Light is a subsidiary, quickly defended the integrity of the plant when questioned by concerned analysts.

Lewis addressed one of the principle allegations leveled at the utility about construction of Waterford-3. It has been charged that there are cracks in the foundation base-mat—a 12-ft thick concrete structure that extends out under the whole plant area.

Referencing independent consultant studies on the problem that recently had been delivered to LP&L, Lewis told the Chicago analysts, "These independent studies indicate that the mat is absolutely sound and that there are no structural problems with it."

The staff of the Nuclear Regulatory Commission, after looking into the matter, concluded that while there indeed were cracks in the foundation base-mat, they were not likely to affect the component's structural integrity.

But according to the NRC's Sherwin Turk, the agency has advised LP&L to implement surveillance of the facility's foundation mat to make sure that the water, which currently flows benignly through the cracks, does not later become corrosive, attacking steel reinforcement bars that strengthen the concrete base.

Continued on page 13

SEC adopts 415 rule governing securities sales

WASHINGTON, D.C.—A final rule for the shelf registration of securities has been adopted by the Securities and Exchange Commission.

Implementation of Rule 415 follows 18 months of experience with revised and expanded shelf registration. The procedure allows certain companies to register debt and equity securities with the SEC and then keep them "on the shelf" for up to two years before offering the instruments for sale.

Traditionally, debt and equity securities have been offered immediately after the SEC made the registration effective, although for some time the agency has allowed some instruments to be sold on a continuing basis. The new Rule 415 for the first time institutionalizes the ability of securities issuers to deliberately *delay* the sale of securities after SEC registration approval, pending the development of what the seller determines is a vigorous market.

The final rule, which became effective December 31, 1983, authorizes certain domestic securities issuers, including electric utilities that can meet specific criteria, to take advantage of this delayed issuance. But this 415 authorization takes place against a complex backdrop of regulations governing "traditional shelf filings" that have been in effect for years and remain virtually unchanged by the new rule.

In general, the rule is available for securities sellers qualified to use the so-called short-form registration statements. Traditional shelf offerings also continue to be available.

Specifically, short form S-3 requires that company stock have an aggregate market value (not counting that held by company affiliates) of at least $150 million. However, a company can qualify if it has $100 million in stock and an annual trading volume of at least three million shares.

The S-3 form defines non-convertible debt or preferred securities as "investment grade" if, at the time of the effectiveness of the registration statement, at least one nationally recognized statistical rating organiza-

Continued on page 4

T-G order famine ends; Westinghouse lands twin-unit order

ORLANDO—A two-year famine in large steam turbine-generator ordering by U.S. utilities ended in late December with an announcement by Westinghouse's steam turbine generator division that it landed an order.

Westinghouse said it will supply two 572-MW units to Southwestern Public Service Co. Engineering on the first unit has started and it is slated for delivery in the late 1980s to a

Continued on page 18

Foreign Power Briefs

- **British Columbia Hydro** has reached a tentative agreement to sell uninterruptible power to four California cities. The utility has sold electricity on an interruptible basis to the Pacific Northwest for about 20 years. The power will be received by the Bonneville Power Administration and then sent to Burbank, the Los Angeles Dept. of Power and Water, Glendale and Pasadena. The new Revelstoke Dam on the Columbia River will provide the electricity. British Columbia Hydro is facing a large surplus of power. The utility announced it has postponed, for at least ten years, its plan to construct a dam on the Peace River. All of the Revelstoke Dam's output will be surplus to the province's requirements. The three-year contract with the California cities is subject to Canadian and U.S. regulatory approval.

- **Hydro-Quebec** said it has slashed its capital spending plans for the next ten years from $33.6 billion (Canadian) to $18.08 billion and dropped its demand growth projection from 3.7 percent to 2.9 percent. The utility said the cuts are needed because of the effects of the recession, new hydro power surpluses, conservation and competition from natural gas. Hydro-Quebec also said it plans to continue its efforts to sell electricity in the northeastern U.S. This is the second time the 10-year proposal has been revised. Hydro-Quebec's first forecast in 1980 called for capital spending of $55.5 billion and a demand growth of six percent annually.

- **Japan and the United States** have signed a five-year, $10-million agreement to collaborate on tests of candidate structural alloys for future fusion energy devices, announced the Department of Energy. The joint program with the Japan Atomic Energy Research Institute provides for the use of two high neutron intensity research reactors at Oak Ridge-National Laboratory for irradiation testing of both U.S. and Japanese-developed fusion materials. Under the agreement, the two countries will share costs of the materials irradiation program scheduled to begin early in 1984.

- **Chinese-made hydroelectric** turbine generators will be sold in the U.S. by Westinghouse Electric Corporation. Westinghouse said it signed a memorandum of intent with China National Machinery & Export Corp. for small hydro units rated to 25,000-kW. Westinghouse will provide installation, construction and maintenance services.

- **Malaysia and Singapore** will connect their electricity supply grids at the end of 1984, according to Malaysia's National Electricity Board. Circuits will be built that are capable of sending 200 MW between power plants in Singapore and Johore, Malaysia. The Board said five more electricity-sharing agreements are being worked on between the members of the Association of South East Asian Nations—Indonesia, Malaysia, the Philippines, Singapore and Thailand.

- **The Philippines National Power Corporation** (PNPC) is planning to cut its dependence on oil-fired electricity generation in half over the next three years. At a recent meeting of the ASEAN Electrical Engineering Contractors in Bangkok, PNCP Director Conrado del Rosario told attendees that the percentage of Philippine electricty generated by imported oil should drop from 65 percent to 35 percent by 1986. He said the potential for the development of Philippine geothermal power exceeds 10,000 MW. Roasario said that by the year 2000 electricity demand is predicted to be anywhere from 10,000-12,000 MW.

In This Issue

Editorial 4
Calendar 5
Acid rain regulations requiring scrubber backfits on utility power plants seem likely in 1984.......... 8
Electric Industry Man of the Year nominees are listed, with citations, biographical sketches and a ballot card so you can vote for your choice. ... 14
Westinghouse has reorganized its steam turbine generator division to deal with the downturn in utility business.G 19
15-year old device still offers best galloping conductor protection.T/D .. 32
New Products 35
New Literature.......... 39
Advertisers' Literature.......... 40
Personnel 41
Regulatory Review 42
Readers' Service 43
Management Methods 46

EL&P readers whose responsibilities include both Generation and Transmission/Distribution receive both technology sections. Other readers receive the technology section that applies to their respective area of responsibility. The Generation edition is indicated by a single dot (•) in the upper right corner of page 1; the T/D edition carries two dots (• •). All readers receive EL&P's industry news section.

GPU Nuclear president resigns; NRC staff recommends restart

PARSIPPANY, NJ—In an effort to win NRC approval to restart the undamaged TMI-1 reactor, General Public Utilities Corp. Chairman William G. Kuhns announced that GPU Nuclear (GPUN) President and Director Robert C. Arnold has resigned.

Shortly after the announcement, the Nuclear Regulatory Commission staff recommended that TMI-1 be allowed to operate at 25 percent on a test basis.

During a November NRC meeting, Kuhns also unveiled GPU's plans for the formation of an independent Nuclear Safety and Compliance Committee.

Arnold said in his resignation letter that "...because of the visible and central role I have had in TMI activities over the last four and one-half years, it seems certain that acceptance of GPU's position that TMI-1 will be operated by a new organization with different management than that which was in place at the time of the accident is improved if I step aside."

He was reassigned to a position with the company's non-nuclear operations, said the utility.

Conditions for restart

NRC spokesman Bob Newlin said the staff recommended three preconditions to a TMI-1 restart. First, the investigation into the unit 2 leak rate falsification charges as they pertain to unit 1 must be resolved. Newlin said that could occur shortly. Second, the staff said the plant should not operate above 25 percent during the testing period. And finally, said Newlin, the unit would be under 24-hour NRC inspection during the restart.

Another issue to be dealt with by the commission is whether to allow a restart before a hearing is held on the status of the steam generator tube repairs done on the reactor.

In a Dec. 7 meeting, the NRC staff recommended that resart be allowed without a hearing. The staff said there are no siginificant hazards involved in resarting without holding a hearing first. At press time, the commission was expected to decide on the issue.

Newlin said the only other meeting scheduled by the full commission was for Dec. 19, when a "closed-door" session was to be held to consider all the issues and remaining questions.

Newlin said a restart decision would not be made at the meeting, but that the commissioners would come up with "some general guidance" on the future of the case.

Even though things seem to be quickly moving along, Newlin said there still "has been no date set for a restart decision."

GPUN waiting for OK

GPUN spokesman Doug Bedell said the preconditions to restart recommended by the NRC staff are acceptable to the utility and that GPUN is awaiting a NRC decision. He said TMI-1 will be ready for a restart on January 15.

Just one week earlier to the utility's announcement, GPU released the findings of 83-year old Ret. Admiral Hyman G. Rickover's investigation into GPU Nuclear. He concluded that "...the corporation has the management competence and integrity to safely operate TMI-1."

One of the major stumbling blocks for the NRC in deciding whether to allow the reactor to restart has been the question of management integrity at GPU Nuclear. Commissioner Victor J. Gilinsky has on numerous occasions called for a complete overhaul of GPU Nuclear's top management.

In June 1983, GPU reassigned 15 professional, supervisory and middle and upper management employees at the plant in order to resolve the management integrity issue.

Clark new president

Kuhns "regretfully accepted" Arnold's resignation and said current GPU Nuclear Executive Vice President Philip Clark will succeed Arnold. GPU Nuclear Vice President Edwin Kintner was named to replace Clark.

"We are hopeful that the combination of the management changes announced today, and those implemented last summer, will provide the commission with the basis to proceed on the TMI-1 restart decision while the remaining open issues are investigated and resolved," stated Kuhns.

The Nuclear Safety and Compliance Committee will be made up of three new outside directors that will be added to the Board of GPU Nuclear. The utility is currently examining candidates for posts and has set no timetable for filling the slots.

Kuhns said the committee will be financed by the GPU operating company owners, and will include a staff to be selected and supervised by the committee. The group's role will be to monitor the operation and maintenance of GPU's nuclear units. Kuhns said the committee will also be expected to provide "... independent and integrated evaluation of their own in-plant observations, NRC inspections; industry evaluations and any other pertinent information."

A GPU spokesman said the committee will be permanent.

Rickover's conclusion

In September 1983, Kuhns asked Rickover to assess the soundness of GPU Nuclear. Working with three associates, Rickover interviewed personnel, reviewed documents and came to the conclusion that GPU Nuclear "has the management competence and integrity needed to safely operate the undamaged reactor.

For his approximately two and one-half months work, GPU said it will pay $25,000 per month for three months to the H. G. Rickover Foundation, where Rickover will then distribute the money to the charities of his choice.

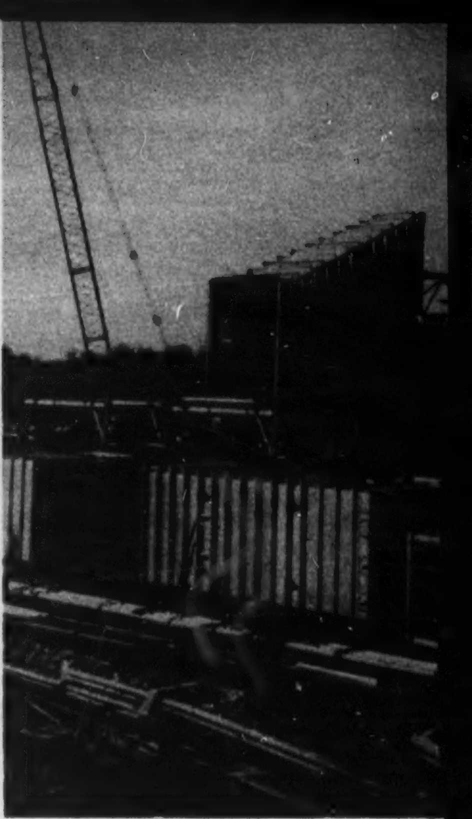
Rickover said the evaluation offered him the "...opportunity to apply the successful principles on which the (U.S.) Naval program was based to an evaluation of GPU Nuclear's competence to operate TMI-1."

Recommendations

Five recommendations came out of Rickover's report. He suggested:
1. GPU Nuclear devise a plan so that TMI-1 and the Oyster Creek plants achieve a ranking in the top one-sixth of all commercial power plants in the INPO evaluations.
2. Senior management become technically informed and personally familiar with plant conditions.
3. Personnel in the TMI-1 training department responsible for training operators who are not yet qualified as senior reactor operators be qualified as soon as possible.
4. GPU Nuclear Corp. should continue to reduce its dependence on the use of consultants.
5. The public address system in the plant be upgraded.

BEST COPY AVAILABLE

Acid rain regs will be falling on utilities in '84, but not too hard



Robert Smock
Managing Editor

Acid rain regulations are coming. They'll probably come this year, requiring retrofits of sulfur dioxide scrubbers on some old power plants. That's the bad news.

The good news is that the regulations will probably be much milder than the harsh measures proposed in federal legislation in 1983. That's because action on acid rain will probably not come in the form of new laws from Congress but from the administration in the form of Environmental Protection Agency regulations.

The Clean Air Act empowers EPA to reduce sulfur dioxide emissions from existing sources if the administrator deems it necessary to control pollution crossing an international boundary. With the Canadians screaming for action by the U.S., the stage is set.

Action by EPA is likely because acid rain was the issue the administration used to defuse the Burford-Gorsuch/toxic waste fiasco of a year ago. As you'll recall, that was developing into a major political liability for the Reagan administration. The president neatly solved the problem by dumping Burford, bringing in William Ruckelshaus as a "Mr. Clean" to run the EPA, and promising action on acid rain.

Through the course of the summer pressure mounted for action. The Canadian government and politicians from northeastern states in the U.S. complained about their dying lakes and forests. A total of 15 bills was introduced in Congress calling for controls. Several scientific groups published reports in mid-summer suggesting that sulfur dioxide from power plants causes acid rain.

In response, the administration, through EPA chief Ruckelshaus, let it be known that a proposal would be out by October. However, the deadline passed and no action was taken.

There are various explanations of what happened. The most likely is that political pressure was relieved by international events—the bombing in Lebanon and the invasion of Grenada. Attention was diverted. When Ruckelshaus took his acid rain recommendations to a committee of high-level administration officials they were brushed aside as too costly and unnecessary. The EPA head was sent back to the drawing board while Reagan's advisors waited to see how the political winds would blow. That's where the situation now stands.

Action is likely in 1984 because acid rain is a political time bomb that the administration does not want to allow to blow up. Failure to act would hand over an issue to political opponents who desperately need a good, scary one like acid rain.

Observers are looking to the presidential primary election in New Hampshire next month for an indication of how potent an issue acid rain will be. John Glenn has already said he favors action, even though he comes from a high-sulfur-coal mining state. New Hampshire is right in the middle of the region that is squawking the loudest about damage so, even though most of its voters are rock-ribbed conservatives, it should provide a good test for the political significance of acid rain.

Science and acid rain

One of the major problems in deciding what action to take, if any, to control acid rain is the lack of scientific data or understanding about it.

Of the many groups of scientists working on the problem, the most important is the National Acid Precipitation Assessment Program. This group has the most effect on policymakers, both in EPA and Congress.

It is part of a federal government program that was started by the Acid Precipitation Act of 1980. It was intended to advance the conversion of oil-fired power plants to coal by deflecting acid rain-based objections through a 10-year scientific study. It involves 12 federal agencies and will spend $22 million this year.

The federal task force's most recent annual report was issued last summer and was one of the sources of pressure on policy makers because it said that the major contributor to acid deposition in North America is probably man-made pollution. However, the report also supported those urging caution on acid rain controls by pointing out that no exact link can be made yet between specific emissions and acid rain patterns.

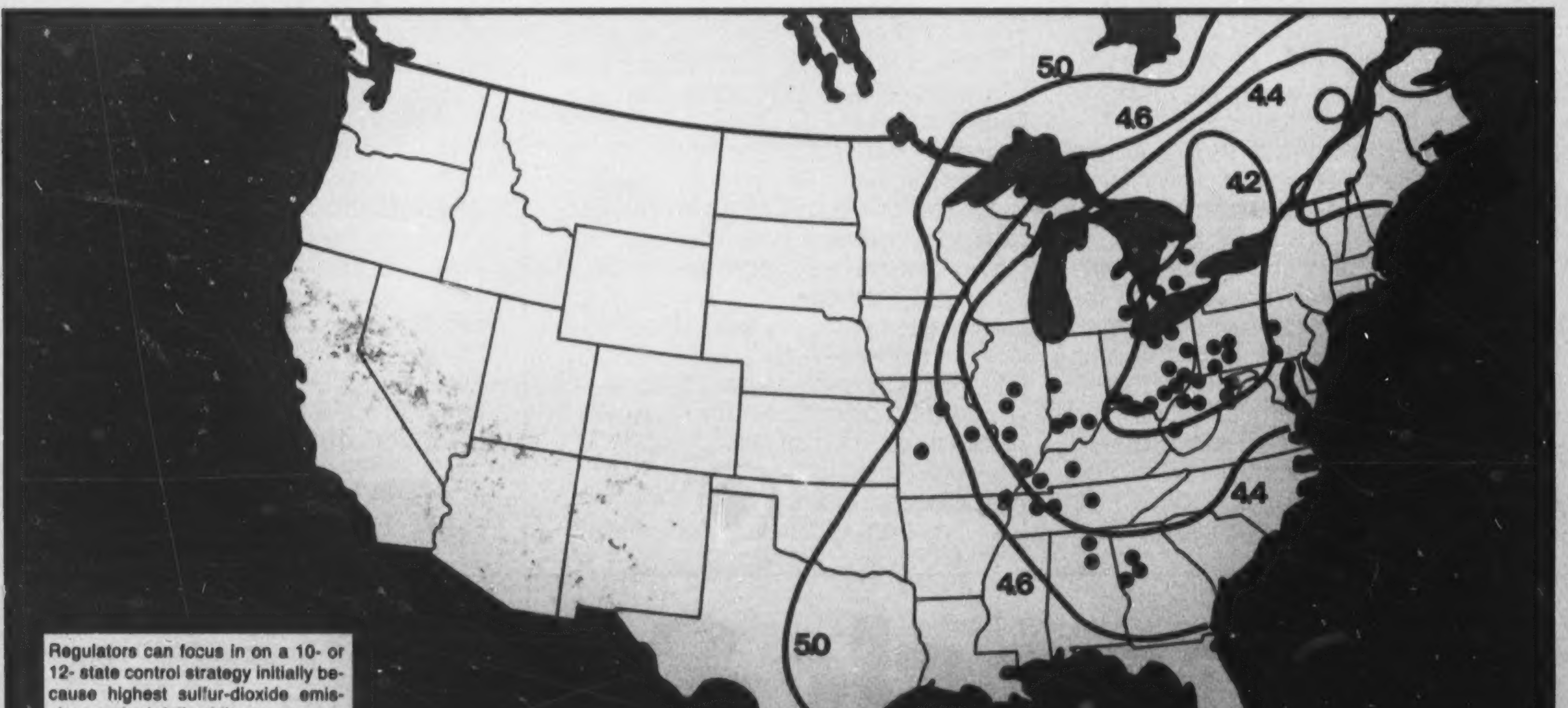
Wait 'til 88

The top EPA scientist on the task force, Gary Foley, says that information on acid rain right now is sparse but the pace is picking up fast. "We expect to have a lot accomplished by 1988," he promises. Within five years, says Foley, scientists will be able to quantify damage from acid rain, specify what level of acid rain is acceptable, and specify what emissions should be reduced to control unacceptable acid rain.

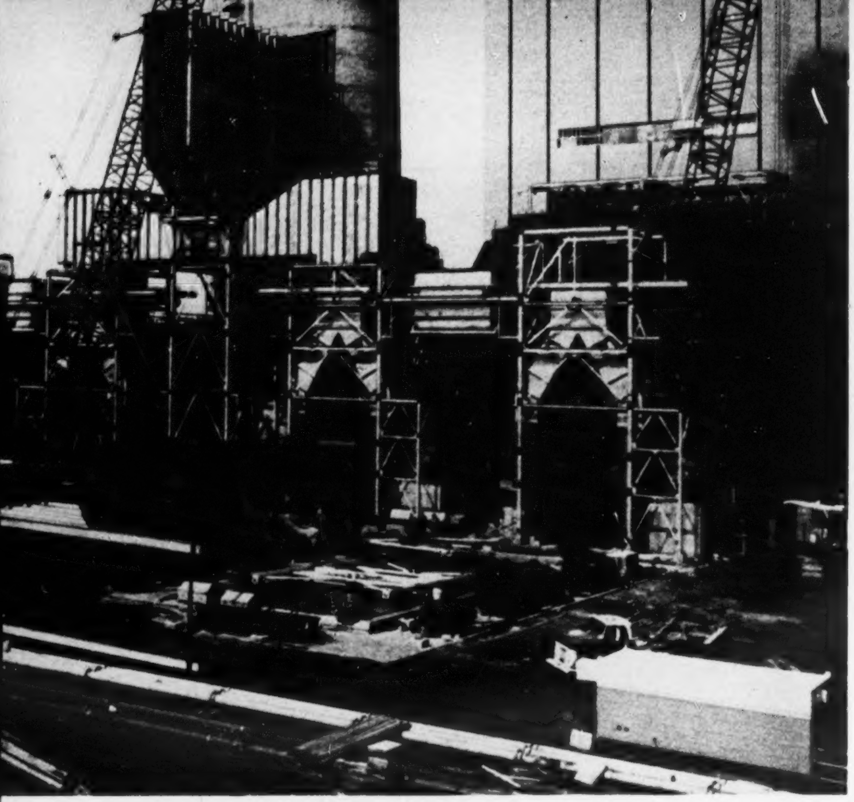
"Existing atmospheric models can not be used with accuracy," says Foley. Such models are necessary to link areas being damaged to specific plant emissions. Foley says a reliable model should be in use by 1986.

Should the politicians wait 'til 88? "It's a decision for the policymakers whether they want to wait," says the EPA scientist.

The head of the federal research task force is Chris Bernabo from the National Oceanic and Atmospheric Administration. He says that acid



Regulators can focus in on a 10- or 12- state control strategy initially because highest sulfur-dioxide emissions and rainfall acidity are concentrated in a relatively small area. The 50 largest sulfur-dioxide sources, indicated with circles on the map, account for half of utility emissions. Annual rainfall pH is shown.



Sulfur dioxide scrubbers, required on all new utility power plants, are now commonplace in the industry. Shown is a scrubber now under construction at Public Service of Indiana's 650-MW Gibson unit 5 capable of removing 85 percent of the SO_2.

1. TOP 50 COAL-FIRED POWER PLANTS IN EASTERN NORTH AMERICA RANKED ACCORDING TO TOTAL SO_2 EMISSIONS IN 1979

Rank	Plant	State	Country	Estimated SO_2 emission thousands of metric tons/year
1	Paradise	Kentucky	U.S.A.	372.5
2	Muskingum	Ohio	U.S.A.	340.2
3	Gavin	Ohio	U.S.A.	339.5
4	Cumberland	Tennessee	U.S.A.	289.7
5	Monroe	Michigan	U.S.A.	264.8
6	Clifty Creek	Indiana	U.S.A.	263.7
7	Gibson	Indiana	U.S.A.	26[illegible].1
8	Baldwin	Illinois	U.S.A.	257.9
9	Labadie	Missouri	U.S.A.	224.0
10	Kyger Creek	Ohio	U.S.A.	205.5
11	Bowen	Georgia	U.S.A.	202.6
12	Conesville	Ohio	U.S.A.	188.8
13	Mitchell	West Virginia	U.S.A.	186.2
14	Hatfields	Pennsylvania	U.S.A.	167.3
15	New Madrid	Missouri	U.S.A.	164.0
16	Sammis	Ohio	U.S.A.	160.7
17	Lambton	Ontario	Canada	160.2
18	Wansley	Georgia	U.S.A.	159.7
19	Homer City	Pennsylvania	U.S.A.	159.1
20	Johnsonville	Tennessee	U.S.A.	157.9
21	Nanticoke	Ontario	Canada	156.0
22	Gaston EC	Alabama	U.S.A.	154.8
23	Montrose	Missouri	U.S.A.	147.1
24	Harrison	West Virginia	U.S.A.	142.8
25	Brunner Isl.	Pennsylvania	U.S.A.	142.0
26	Coffeen	Illinois	U.S.A.	141.8
27	Cardinal	Ohio	U.S.A.	140.8
28	Eastlake	Ohio	U.S.A.	137.4
29	Kammer	West Virginia	U.S.A.	136.8
30	Kincaid	Illinois	U.S.A.	136.3
31	Keystone	Pennsylvania	U.S.A.	127.2
32	Stuart J.M.	Ohio	U.S.A.	125.6
33	Cayuga	Indiana	U.S.A.	121.7
34	Shawnee	Kentucky	U.S.A.	111.0
35	Gallatin	Tennessee	U.S.A.	110.6
36	Montour	Pennsylvania	U.S.A.	109.4
37	Big Bend	Florida	U.S.A.	109.2
38	Conemaugh	Pennsylvania	U.S.A.	108.9
39	Widows Creek	Alabama	U.S.A.	106.0
40	Amos	West Virginia	U.S.A.	105.2
41	Thomas Hill	Missouri	U.S.A.	104.9
42	Joppa Steam	Illinois	U.S.A.	104.4
43	Mt. Storm	West Virginia	U.S.A.	102.5
44	Petersburg	Indiana	U.S.A.	100.7
45	Beckjord	Ohio	U.S.A.	99.7
46	Avon Lake	Ohio	U.S.A.	98.0
47	Fort Martin	West Virginia	U.S.A.	94.6
48	Miami Fort	Ohio	U.S.A.	94.2
49	Lakeview	Ontario	Canada	91.4
50	Yates	Georgia	U.S.A.	88.6

Source: Ontario Ministry of Environment

rain is causing damage, but faced with the question of what control strategy should be used, says, "We can't write the prescription yet."

Bernabo says that the research to date has shown there is long-range transport of combustion-related emissions that cause acid rain, but that linking a specific source to a specific receptor area is an unsettled question. He says it is certain that some lakes and waterways are being damaged, adding that 20 percent of the lakes in the Adirondack region of New York are susceptible to damage due to low natural alkalinity.

On the other hand, results of research so far on crop damage have been "highly confusing," says Bernabo. In some cases researchers have seen harm from acid deposition; in other experiments the acid rain acts as a fertilizer. Another open question is the relationship between acid rain and the dieback of Spruce trees that's occurring in the eastern U.S.

"We have problems now because we didn't collect the basic data in the past," says Bernabo. "We're trying to rectify that."

The scientist does not, however, conclude that politicians should wait for definitive results from the researchers. "Politically, just a threat of damage may be enough to motivate action," he notes. "The politicians have moved ahead of the scientists, which is not unusual for these issues," he says, adding that deciding when you know enough to act is up to the politicians, not the scientists.

Bernabo says that administration officials favoring and those opposing acid rain action are at a standoff right now, "Administration policy is on the edge."

The scientists haven't provided any firm guidelines but they have set the stage for modest action on acid rain in 1984 to be followed by more far-reaching regulations in five years if the research results then available support more drastic action.

EPA's options

Some clues as to what that modest proposal might be were presented at a recent meeting on acid rain by Paul Stolpman, special assistant to the director of EPA's office of policy and analysis. Stolpman first outlined the chief problems:

- What states should be affected by the regulations? Stolpman noted that action has been proposed for the entire continental U.S., at one extreme, and for a region as small as four northeastern states at the other. In the first round of analysis EPA concentrated on the 31 states east of and bordering the Mississippi River—the states where rainfall pH is low, as shown on the map.
- How much should emissions be reduced? Noting that sulfur dioxide emissions in the 31 state region were 19 million tons a year in 1980 (16 million from utilities), Stolpman reported that EPA analyzed, in detail, strategies calling for reductions of 4, 8, and 12 million tons per year by 1995, as shown in Table 2. Additional variations for other state groupings were also checked.
- How should the reductions be allocated? Each state could be given a quota, or the reduction could be spread over the most prolific sources of SO_2, or controls could be imposed on the SO_2 sources that are linked to the worst damage, Stolpman said.

As the analysis proceeded last summer, the advisor related, EPA policymakers converged on favoring the 8 million ton reduction option in the broad, 31-state region. Main reason was that the cost curve kneed upward sharply at the 8-10 million ton point. As shown in Table 2, the annualized cost and present value of cumulative costs for the 12 million ton option are disproportionately high.

"The 12 million ton reduction gets you more than you need at massive cost," said Stolpman, "and the 4 million ton reduction doesn't get you there in terms of protecting sensitive areas." The late summer focus was on a strategy to slash SO_2 emissions by 8 million tons a year by 1995.

High sulfur coal vs. low sulfur

One of the many troublesome subproblems associated with this strategy is the issue of coal miners' jobs in states that produce high-sulfur coal.

As shown in Table 2, utilities would probably achieve the 8 million ton reduction in the EPA analysis by retrofitting scrubbers on 19,000 MW of existing capacity and by replacing high-sulfur coal in existing plants without scrubbers with 80 million tons of imported, low-sulfur Western coal.

The emission reduction could be achieved without increasing imports over the base case by increasing the capacity retrofitted with scrubbers to 80,000 MW, Stolpman reported. That would increase the cumulative capital cost from $6 billion to $25 billion.

That might appear prohibitive but remember that the high-sulfur coal producers fought and won a similar battle with the 1977 Clean Air Act amendments. Prior to that change in the law utilities could avoid installing scrubbers on new plants by burning low-sulfur coal. The change required all new power plants to install scrubbers regardless of the sulfur level of the coal burned. That effectively halted the transport of low-sulfur western coal to eastern utilities for use in new power plants.

Now the battle is shaping up again over what to do with the older plants that are still burning high-sulfur coal and don't have scrubbers. The coal industry has split.

The unionized, high-sulfur coal producers located chiefly in states east of the Mississippi are lining up against the non-unionized low-sulfur companies in the West. In fact, the low-sulfur group recently formed a lobbying organization called the Alliance for Clean Energy to fight for the "least cost" approach to reducing SO_2.

A more modest strategy

EPA's Stolpman reported that the broad-regional 31 state, 8 million ton plan has been shelved because the, "complicated nature of politics, costs, and environmental control options

BEST COPY AVAILABLE

The scrubber retrofit cost issue deflected the 31-state crackdown planned last summer...can it deflect the 10-state strategy now being developed by EPA?

were underestimated."

The new focus is rumored to be on a sub-regional plan calling for reductions in stages. The first stage would affect the 10 or 12 states that produce the most SO_2 emissions and are closest to the area in the northeast that's suffering aquatic damage according to research findings already in from the federal task force. The "second shoe" would drop in 1988 on other states based on future research.

The 10 state group includes the six New England states plus New York, Pennsylvania, Ohio, and West Virginia, Stolpman reported. Michigan and Indiana could be added to get a 12-state group. The advisor said the strategy could go as far as targeting specific plants in the target states.

Emission control methods

The methods that can be used by utilities to reduce SO_2 emissions from older coal-fired power plants are shown in Table 3. The most popular methods will probably be conventional scrubbers and low-sulfur coal (if it's to be permitted).

Sulfur dioxide scrubbers have made great inroads in the utility industry since EPA began forcing their use about 10 years ago. There are 114 generating units in the U.S. with flue-gas desulfurization devices, totaling 46,000 MW or 16 percent of coal-fired capacity in place. (Note that only 17,000 MW of that scrubbed capacity is in the 31-state acid rain region. That's because most of the growth in the utility industry since passage of the Clean Air Act in 1970 has been in the west.)

EPA projects that, without any change in the regulations, there will be another 121 units with scrubbers in operation during the next 10 years, totaling another 70,000 MW. At that time, 34 percent of coal-fired capacity will have scrubbers. For the most part these scrubbers will be on new plants built since 1971, but there are a few retrofits.

EPA reports that utilities are becoming highly familiar with conventional scrubber technology. There are 14 utilities with more than 100,000 operating hours of experience.

At the recent flue-gas desulfurization symposium sponsored by EPA, Paul Ireland of Stearns-Roger Engineering Corp. reported some preliminary results from an acid-rain retrofit cost study the firm did for EPRI. He said the intent of the study was to provide guidelines for utilities faced with the need to retrofit. Guidelines have been completed for limestone scrubbers, Ireland said, and similar guides are being prepared for five other scrubber types. The final report is due this month.

Ireland reported that the average premium a utility will have to pay for a scrubber retrofit over the cost of a scrubber for a new unit is about 30 percent. The range for potential retrofit cost premiums is 10 to 100 percent.

Another speaker from Stearns-Roger, describing the results of an EPRI study on costs for scrubbers on new capacity, said the costs will be:

- Limestone—$175/kW, 18 mills/kWh;
- Lime—$165/kW, 20 mills/kWh;
- Lime dual alkali—$150/kW, 17 mills/kWh;
- Limestone dual alkali—$160/kW, 16 mills/kWh;
- Limestone, forced oxidation—$175/kW, 16 mills/kWh;
- Chiyoda Thoroughbred 121—$140/kW; 14 mills/kWh;
- Saarberg-Holter—$130/kW, 16 mills/kWh.

These "conventional" technologies all have high capital costs in common. (Retrofit costs will be 10 to 100 percent higher than these.)

An EPA official, John Milliken, put the retrofit costs even higher. He said an EPA analysis showed conventional limestone scrubbing retrofitted to a 500-MW, high-sulfur-coal burning power plant would cost $270/kW. Use of adipic acid would only reduce the cost to a reported $240/kW.

2. EMISSIONS, UTILITY COST, AND COAL MARKET IMPACTS OF ALTERNATIVE 4, 8, AND 12 MILLION TON SULFUR DIOXIDE EMISSION REDUCTIONS

	Year		Intrastate trading changes from base case Reduction from 1980 Levels		
		Base Case			
Category	1980	1995	12	8	4
SO_2 Emissions—Eastern States					
Utility	16.2	17.6	−13.8	−10.1	−6.6
Industrial	2.6	3.3	−0.4	−0.4	−0.4
Total	18.8	20.8	−14.2	−10.5	−7.0
Utility					
Annualized Cost (10^9 $'s) Cap.	–	–	+3.7	+0.7	+0.1
O&M	–	–	+1.8	+0.5	+0.1
Fuel	–	–	+3.6	+2.5	+1.4
Total	–	–	+9.1	+3.7	+1.6
Industrial Annualized Cost (10^9 $'s)	–	–	+0.6	+0.6	+0.6
Cumulative Capital Cost[3] (10^9 $'s)	–	–	+32.3	+6.2	+0.6
Present Value of Cost (1983-2010) (10^9 $'s)	–	–	+222.1	+50.9	+15.6
Coal Production (10^6 tons)					
N. Appalachia	185.1	213.0	−43.4	−61.6	−39.6
C. Appalachia	232.8	294.8	+50.2	+55.7	+47.2
S. Appalachia	26.4	25.8	−2.3	+0.9	−0.2
Midwest	134.4	181.9	−97.4	−92.5	−73.8
West	251.0	584.6	+94.0	+97.7	+63.1
Total	829.7	1300.1	+1.1	+0.2	−3.2
Average Cost-Effectiveness ($/ton SO_2 Removed)	–	–	660	370	250
Scrubber Capacity (GW)	16.7	43.0	+116.2	+18.9	+1.3
% Change in Electricity Rates	–	–	8.0	3.2	1.4
Western Coal Shipped East	36.7	74.2	+79.9	+79.7	+48.6

Source: EPA Acid Deposition Task Force, August 1983.

Dry scrubbers would only cost $160/kW, but they've yet to be proven on high-sulfur applications.

Furnace injection revived

EPA analysts are looking at a cheap and dirty desulfurization method called furnace injection as a way to provide a low-cost retrofit option—a mere $60/kW says Milliken. The method calls for blowing lime or limestone particles into the furnace with the coal and collecting the resulting calcium sulfate in a particulate collection device at the back end. It's like dry scrubbing without the spray dryer.

EPA policy analysts say this method could be used to reduce SO_2 emissions by 50 percent from older power plants. That's far less than the 90 percent reduction possible with conventional flue-gas desulfurization, but 50 percent might be acceptable in a modest, low-cost strategy intended for early adoption. It could even be combined with burners designed for low nitrogen oxide emission—the limestone injection, multi-stage burner, or LIMB, as shown in Table 3.

Mike McElroy, an EPRI project manager, described at the symposium some work EPRI is doing to develop furnace injection technology. He noted that bench- and pilot-scale work has shown a high potential for boiler tube slagging, fouling, and erosion, especially in typical retrofit applications. However, he added that work being done by Mitsubishi Heavy Industries shows that conventional sootblowing equipment may be capable of dealing with tube deposits. McElroy said the cost of a furnace injection retrofit could be a low $70 to 80/kW, even including the additional particulate collection capacity that would be required. He said a test on a 50- to 100-MW scale utility boiler is planned for late 1985 and that a full-scale test is planned for 1988.

Bill Elder, an experienced scrubber engineer from TVA, recalled that the utility industry had a lot of bad experience with furnace injection technology in the late '60s and abandoned it. "We have a lot of information in the files on this," he told the symposium, adding, "Let's use it."

3. RETROFIT CONTROL TECHNOLOGIES FOR COAL-FIRED UTILITY BOILER

Process	SO_2 and NO_x removal efficiencies	Status	Estimated* capital costs ($/kW)	Applicability	Problems
Flue gas desulfurization (lime or limestone scrubbing)	90% SO_2 Reduction	Commercial	200 to 300	Most large utility boilers; costs could sharply increase over estimated values for difficult retrofits.	High costs; especially for difficult retrofits. Large quantities of wet waste to be disposed of.
Physical coal cleaning	20 to 30% SO_2 Reduction	Commercial	40 to 50	Centralized cleaning facilities can allow broad applicability	Limited SO_2 removal; especially for difficult to clean coals. Large quantities of pyrite solid residue for disposal.
Low-sulfur fuel switching	60 to 80% SO_2 Reduction	Commercial	26 to 61	Most utility boilers	Boiler derating sometimes required. Potential displacement of locally mined coal.
Low-NO_x burners (second generation)	60 to 70% Reduction	Early Commercialization	2 to 7	Most modern utility boilers	NO_x removal only; no SO_2 removal.
Limestone injection multistage (Low NO_x) burners (LIMB)	50 to 60% SO_2 Reduction 50 to 60% NO_x Reduction	Developmental	27 to 37	Most utility boilers	Technology will be commercial no earlier than 1985. Questions must be resolved regarding performance and boiler reliability.

*Based on 300 MW, 3% sulfur coal, and Dec. 1982 dollars.

Source: *Annual Report*, 1982, National Acid Precipitation Assessment Program

2/16/84
C8650-4

Volume 62, Number 2
February 1984

09235 1984293 W 2 2024
SUITE 800 COPY # 2
STATISTICAL REFERENCE IND
CONGRESSIONAL INFO SVC D
4520 EAST-WEST HWY STE 800
BETHESDA MD 20814

Electric Light & Power

THE NEWS MAGAZINE OF ELECTRIC UTILITY MANAGEMENT AND TECHNOLOGY

NARUC says shareholders should pay up to one third of EEI membership dues

WASHINGTON, D.C.—Up to 33 percent of Edison Electric Institute dues, now borne by ratepayers, should be paid by participating members shareholders, a preliminary report by the National Association of Regulatory Utility Commissioners (NARUC) has concluded.

The investigation into EEI expenditures was conducted by the NARUC Staff Subcommittee on Accounts.

The subcommittee also concluded that all contributions by member utilities to the EEI media communications program should be borne by shareholders, and that ratepayers of member utilities were the rightful contributors to programs administered by EEI, such as the Electric Power Research Institute and the Nuclear Safety Analysis Center.

The funds for at least nine such programs were channelled through EEI in 1982.

EEI has taken vigorous exception to many of the conclusions of the report and has challenged a number of the subcommittee's findings.

Purpose not achieved

The point of the NARUC probe into EEI expenditures is to provide some generic guidance to aid state commissions in determining which items should be expensed. However, in its preliminary report, the subcommitee concedes that it was unable to accomplish its main purpose: to clearly delineate those EEI activities and expenditures that legitimately should be charged to ratepayers and those that are identified with shareholder interests.

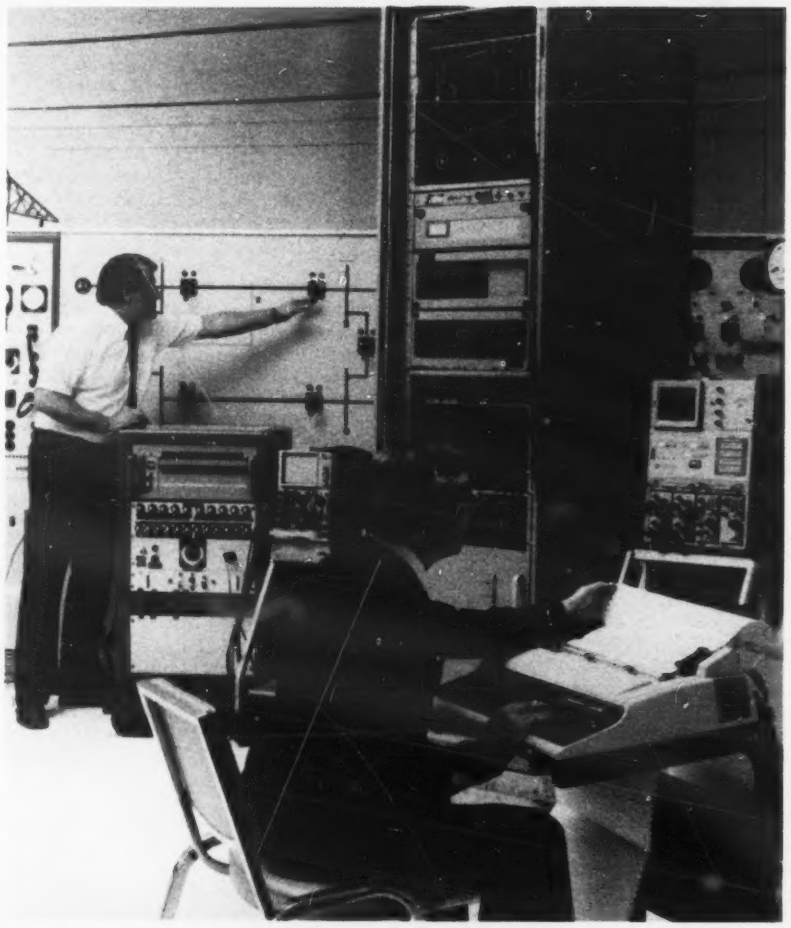
The NARUC subcommittee blames its lack of success on EEI's failure to respond comprehensively to its inquiries. Specifically, EEI refused to disclose the salaries of its staff attorneys, and initially declined to provide audit reports of its financial statements.

EEI said subsequently that on November 22 it had supplied the audit reports.

In a letter to EEI president William McCollam, Jr., NARUC subcommittee chairman John J. Gibbons, a member of the California Public Utilities Commission, charged that despite the answers that EEI provided to subcommittee inquiries, "the frank and open approach that we had hoped for is missing."

"...There simply is not sufficient information in the responses to segregate those expenditures that regulatory commissions might consider to be more properly attributable shareholders than to ratepayers," Gibbons wrote.

Continued on page 11



Industry 'first' shipped

The first of two prototype microprocessor-based digital transmission-line protection and control systems has been shipped to Public Service Electric & Gas Co. The system, shown above during manufacturer's testing, will be installed at the utility's Branchburg substation in Newark, NJ. Developed under an Electric Power Research Institute contract by General Electric, the system is designed to survive extreme substation temperature, humidity and electro-magnetic interference environments. Initially the system will be tested in a monitoring mode, then will be used for primary 500-kV line protection. A second unit will be installed later at the Deans substation end of the line.

PSI abandons Marble Hill

INDIANAPOLIS—Citing the inability to continue financing the Marble Hill nuclear plant, Public Service Indiana has decided it will abandon the project.

The announcement comes on the heels of the findings of a task force established by the Indiana governor and constituted of area businessmen. The task force concluded, in part, that there was not sufficient economic justification to complete the two-unit nuclear project.

"PSI cannot and will not proceed," said utility spokesman Michael Goss. He added that although the company still believes completion is in the best interest of ratepayers and stockholders, financial and political circumstances have rendered completion infeasible.

Governor Robert D. Orr is up for reelection next year and will be campaigning around the issue of utility rates in the state.

Cancellation not unilateral

Abandonment, which is contingent on the as-yet unobtained concurrence of the Wabash Valley Power Association, PSI's partner in the project, represents something of a watershed decision in the investor-owned electric utility industry. No plant construction has been so far along and been abandonded.

Gov. Robert D. Orr

Unit 1 is about 60 percent complete and unit 2 is about 37 percent complete.

Dividend cut

PSI said on January 17 that it would cut its quarterly dividend by 65 percent—from 72 cents per share to 25 cents per share.

Continued on page 2

Utilities set all-time output record; sales, revenues up in 3rd quarter

WASHINGTON, D.C.—More electricity was distributed in the U.S. during 1983 than in any other year, said the Edison Electric Institute.

The utility association said more than 2.3 trillion kilowatt-hours were distributed by electric utilities during the year, surpassing the previous high set in 1981 by 1.2 percent.

"The unseasonable hot weather we experienced during the summer and the bitter cold of December created tremendous demand for electricity," said Douglas C. Bauer, EEI senior vice president. "Coupled with a healthier economy that rebounded from the recession of 1982, electric output increased 3.6 percent over the previous year."

Bauer said the largest increase in 1983 occurred in the West Central region (ND, SD, MN, NB, KS, IA and parts of MT, WI and MO) where generation increased 5.8 percent above 1982's total.

The Southeast region (FL, GA, AL, NC, SC, KY, TN and parts of MS, WV and VA) distributed 5.1 percent more power than in 1982. The Pacific Northwest region experienced the only decline over 1982 at -1.4 percent.

EEI also reported that the hotter than average summer and a pick-up in business activity helped increase 1983 third quarter electric utility sales, revenues and kilowatthour use.

EEI says that electricity sales in the quarter rose 9.8 percent over 1982's figures, from 550 billion kilowatthours to 603 billion-kWhr.

At the same time, revenues for the electric utility industry jumped from $33 billion in 1982's third quarter to $38 billion in 1983, an increase of 15.4 percent.

Foreign Power Briefs

- **Polish coal** may soon be on its way to Tampa Electric Company. Utility spokesman Greg Truax says Tampa Electric is close to finalizing a deal with a trading company for the delivery of 100,000 tons of low-sulfur coal for its Big Bend power plant. The coal will be shipped in two-50,000 ton carriers for an undisclosed amount of cash. Truax said the price of the coal makes it "very advantageous" to purchase, but that it is only a one-time spot purchase. The recent high cost of Polish coal and the country's political strife has kept Tampa Electric out of the Polish coal market for the past few years, said Truax.

- **Israel's** Ormat Turbines, Ltd. and Southern California Edison Co. have signed an agreement to build and operate a solar pond power plant in California. Edison Senior Vice President Dr. Lawrence T. Papay said the solar pond plant will be the world's largest and will initially produce 15 million-kWh a year. Papay said three more units of equal size will be added later to bring the plant to its eventual capacity of 48,000-kW. Ormat has developed and demonstrated a refined Rankine cycle turbine-generator for solar pond power generation. In a standing pond of salt water, the heavier saline water stays on the bottom. Heat created by solar energy penetrating to the saltier and heavier water at the pond's bottom is trapped. The heated salt water drives the Rankine turbine-generators in which a working fluid with a low boiling temperature is substituted for water.

- **The Japanese Federation of Electric Power Companies (FEPC)** has decided to participate in the research and development programs of Three Mile Island. FEPC will contribute up to 22 engineers and $18 million over a five-year period to R&D at TMI. FEPC said the information learned in the research "will have a significantly positive impact on the promotion of development in nuclear technology, especially in the field of the design of reactors, dismantling and medium- and high-level radioactive waste disposal." General Public Utilities said the agreement will be finalized sometime in February or March.

- **Denmark** will start mass production of a small urban electric car in April. About 2,000 cars will be manufactured by Hope Automobil Industri of Hadsund next year and 10-12,000 in 1985. *Electrical Review* reports that the Hope "Wisper" will operate 100 kilometers between charges. The front wheel drive car has a 7.45-kW, 72V series wound d.c. motor and 12x6V deep cycling lead acid batteries. Marketing Manager Dan Wildenrath said tests to check the car's compliance with U.S. vehicle regulations are taking place in Germany.

- **China's** official news agency Xinhua reports that construction of a 133 km, 220-kV transmission line in northeast China has been completed. The news agency said the line will eventually connect a major hydroelectric station, currently under construction, to the northeast China power grid. Xinhua said the new Baishan hydro plant will have a capacity of 1,500 MW. The first 300 MW unit is expected to be put into operation shortly.

- **The South Korean government** has decided to postpone construction of two nuclear units, KNU-11 and KNU-12. The Ministry of Energy and Resources said construction of the units was to begin in 1984, but now will likely start sometime in mid-1986. Work on six units presently under construction may also be delayed from six to 10 months, said the ministry. Demand growth forecasts have been lowered and estimates of South Korea's foreign debt place it at almost $40 billion, said *Nuclear Engineering International*. The government says it would be very difficult to come up with the money for the two postponed units in the near future.

In This Issue

Editorial 4
Calendar 15
The coal/water slurry fuel business is attracting new suppliers who expect a growing market in the utility industry in the near future.G 23
On-line, real-time dispatcher training simulators are being built into new dispatch computer installations.T/D 26
Pennsylvania Power & Light has developed a "pull-by" procedure for adding control cable to partially filled conduits.G 33
New Products 40
Readers' Service 41
New Literature 46
Advertisers' Literature 47
Personnel 48
Regulatory Review 50
Management Methods 54

EL&P readers whose responsibilities include both Generation and Transmission/Distribution receive both technology sections. Other readers receive the technology section that applies to their respective area of responsibility. The Generation edition is indicated by a single dot (•) in the upper right corner of page 1; the T/D edition carries two dots (• •). All readers receive EL&P's industry news section.

Marble Hill . . . from page 1

In another move directed at alleviating its worsening financial position, the company said it had filed with the Indiana Public Service Commission for emergency rate relief. PSI is asking for $105 million per year to help meet its current financial obligations.

Further, the company's board of directors has asked PSI to begin preparing rate cases for Marble Hill that would seek to recover the utility's investment in the project, which presently is estimated to be over $2 billion.

Cooperative takeover?

Although discussions have been proceeding, no agreement has been reached between PSI and the Wabash Valley Power Association, the generation and transmission cooperative that owns 17 percent of Marble Hill.

Wabash spokesman Craig Palmer said that independent studies conducted by the cooperative show that it is still in that utility's economic interest to complete Marble Hill.

At press time the cooperative was examining whether it would be able to take over the plant, although Wabash itself concedes such an enterprise would be "an uphill fight."

Financing needed

Palmer said that Wabash would be looking at innovating financing techniques, would seek financial commitments from the Rural Electrification Administration and other utilities, and would try to get Public Service Indiana to commit itself to some sort of power buy-back plan. Ideas on such an action were expected to be presented to the Wabash board of directors by February 1.

The board consists of two representatives from each of 24 member systems. Collectively, Wabash serves about 170,000 customers.

Task force findings

Moved by what he contends is consumer concern in the state, Indiana Governor Robert D. Orr in late summer directed the Public Service Commission to suspend its review of the rate control plan submitted by Public Service Indiana. The plan had been offered as the utility's way of securing additional financing for the plant and completing construction (see *EL&P*, September 1983, page 1; December 1983, page 1).

At that time the governor also set up his 5-member task force to conduct an independent review of PSI's financial situation and to provide recommendations dealing with the feasibility of continuing with Marble Hill.

Estimates pessimistic

Calculating that the estimated cost of completing the two-unit nuclear station would be at least $600 million more than the current utility estimate of $7.1 billion, and probably would be even more than this, the task force concluded that "the economic case in favor of completion would have to be much stronger than presented to justify the risk of at least an additional $5 billion above current sunk costs."

In the opinion of the task force, the total costs of Marble Hill, even if completed on schedule, did not justify completion when compared with the alternative of building coal-fired plants, even assuming new SO_2 emission standards.

Benefits optimistic

The task force also found that PSI conclusions, showing benefits from completing the plant flowing to ratepayers after 1996, were optimistic. The task force found that such benefits, if any, would occur much later.

"The most optimistic justification for completion of Marble Hill involves assumptions about the level and pricing of off-system sales which we believe are incorrect," the task force reported. "This justification, even if we were inclined to accept it, would not be strong enough to support extraordinary financing measures such as CWIP or trended rates."

Other recommendations

The task force further recommended that:

- PSI and its shareholders absorb the substantial portion of all Marble Hill costs, up to the point where the utility's ability to access capital markets becomes impaired. To go beyond this point, the task force said, would result in even higher rate increases and/or deterioration of service for PSI customers.
- PSI demonstrate that it has exercised all possible financial remedies, including reassessing its dividend policy, prior to seeking ratepayer participation.
- If ratepayer contributions are necessary, total Marble Hill costs should be amortized over a 20-year period and PSI should not be allowed to earn a return on its investment in the nuclear plant.

Recommendations supported

In endorsing the recommendations of his task force, Indiana Governor Orr said, "As far as I'm concerned, this task force has performed the most comprehensive and objective analysis of the Marble Hill situation to date."

He noted that the task force, comprised of businessmen from Indiana, had no vested interests and were "unconstrained" in proposing remedies. Declaring that the task force had comprehensively investigated the problem, Orr added, "...more analytical talent has never before examined this issue. In addition to the five task force members, the resources of two internationally prominent consulting firms were utilized."

Responding to the task force report PSI chairman Hugh A. Barker emphasized that the company was intent on protecting its financial integrity, noting that shareholders rights to recover their investment in Marble Hill would be "forcefully" defended.

NRC OK's license for LaSalle

WASHINGTON, D.C.—The Nuclear Regulatory Commission has given the go-ahead to Commonwealth Edison for fuel loading and low-power testing at the utility's La Salle County Unit 2 nuclear plant.

In late December, the NRC issued an operating license authorizing the fuel load and low power testing up to five percent full power. La Salle-2 is a boiling water reactor with a capacity of 1078 MW.

Irene Johnson, spokesperson for Commonwealth Edison, said fuel loading was completed early in February and that low power testing was to begin shortly.

Spring start-up

She said the utility hopes to have the unit on-line in April or May.

Unit 1 was licensed in August 1982.

Coal industry sees modest gains in '84; feels utilities won't build up inventories as strike hedge

WASHINGTON—The National Coal Association, trade association of U.S. coal mining companies, predicts that production and consumption of coal in 1984 will be up only slightly over 1983 levels (see table.)

However, a major uncertainty in the forecast is how utilities will deal with the potential for a United Mine Workers strike when their labor contract expires on September 30, 1984. The NCA forecast assumes no strike and no change in consumers coal stockpile levels.

Prior to the 1983-84 winter cold spell utility stockpiles were about 95 days worth of coal, a normal level. In March, 1981, just prior to expiration of the previous labor contract, utility coal stocks had increased to 120 days. However, the coal industry does not feel utilities will build up inventories much above the 100-day level this time, says Jerry Karaganis, NCA vice president for economics. He says the 1981 inventory level is misleading because at least some of the buildup was due to less demand for electricity than expected due to the economic recession.

NCA does not expect utilities to do much of any strike-hedge buying in 1984 because conditions are far different than in the past, says Karaganis. He says that the percentage of coal produced by union miners has dropped to only 40 percent of the total, diluting the effect of a strike and permitting non-union sources to make up much of the lost union production, an effect first seen during the three-month 1981 strike.

NATIONAL COAL ASSOCIATION 1984 FORECAST
(Millions of tons)

Category	1982 Final	1983 Est.	1984 Forecast	Percent Change 1984/83
Domestic Consumption				
Electric Utilities	593	610	618	+ 1.3
Coking Coal	41	39	45	+15.4
General Industry and Retail	70	72	75	+ 4.2
Total Domestic Markets	704	721	738	+ 2.4
Exports To				
Canada: Steam	13	9	9	+ 0.0
Metallurgical	5	6	6	+ 0.0
Total	18	15	15	+ 0.0
Overseas: Steam	27	18	20	+11.1
Metallurgical	60	42	44	+ 4.8
Total	87	60	64	+ 6.7
Total Exports	105	75	79	+ 5.3
Total Consumption	809	796	817	+ 2.6
Consumers' Stock Change	14	-8	0	–
Total Demand	823	788	817	+ 3.7
Production				
East	560	515	540	+ 4.9
West	274	265	276	+ 4.2
Total U.S.	834	780	816	+ 4.6
Prod./Distr. Stock Changes	12	-7	0	–
Imports	1	1	1	–
Total Marketed Supply	823	788	817	+ 3.7

Karaganis says utilities have improved energy wheeling capability substantially in recent years, both inter-utility wheeling and importing from Canada.

He adds that utilities are looking for a good hydro year in 1984 with the big snowfalls this winter so far and nuclear plants promise to contribute more than in the past. All these factors should induce utilities to save money on coal inventory costs by keeping stocks at normal levels.

"It'll be interesting to see what happens," says Karaganis, admitting that there is potential for more consumption, which would be good news for the coal industry.

He says the cold winter may require an upward revision in consumption and production forecasts. The current forecast was made in December before the cold snap set in: "Who could have predicted a 100-year cold wave following a 50-year heat wave the preceding summer?" The cold wave pushed electricity consumption, and hence utility coal consumption, far above expected levels, driving stockpiles well below fall levels. NCA's Vice President Karaganis said there may have to be some inventory rebuilding to get back up to the 100-day level this spring.

Another major variable in the forecast is exports which dropped from a high of 113 million tons in 1981 to 75 million tons last year. NCA looks for a modest gain in 1984.

Karaganis admits the uncertainty in the forecast seems to be on the upside, with increases over the forecasted levels likely. NCA estimates, however, that there is 200 million tons per year of overcapacity in the nation's mines, so the industry should be able to handle any increase.

Seabrook cooling water tunnels completed

MANCHESTER, NH—Two deep-bedrock ocean cooling water tunnels at the Seabrook Nuclear Plant have been completed, said Public Service of New Hampshire (PSNH).

The tunnel system had been under construction since 1977 and is designed to bring ocean water into the plant's turbine-generator buildings to work as a cooling system.

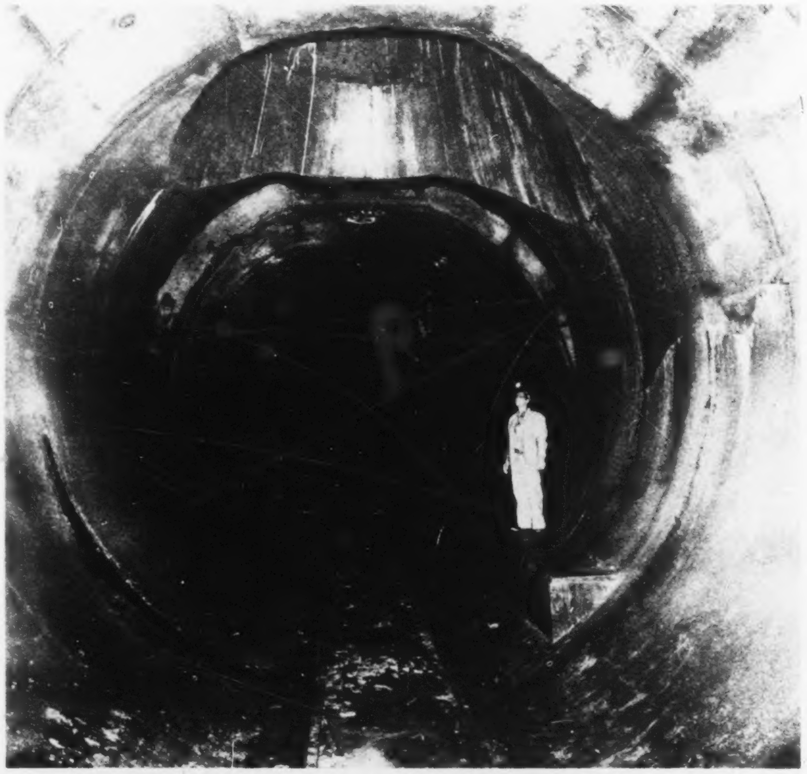
More than three miles long each, the two tunnels start 260 ft below sea level at the Seabrook pumphouse and run parallel to a point under the Hampton-Seabrook Bridge.

At the ocean end, the intake shafts are topped by 30 ft diameter concrete structures that will direct water into the tunnels at a velocity of less than one foot per second, said PSNH.

Water will flow from the ocean through the intake tunnel at a rate of 824,000 gallons per minute, up vertical shafts into the pumphouse where six 3,600-horsepower pumps will feed it into the plant's condenser cooling system.

After traveling through the condenser system, double-nozzle fixtures will diffuse the returning warm water so it will quickly mix with the ocean water.

PSNH said the tunnels are now being allowed to fill with natural groundwater that seeps into them at a rate of approximately 600 gallons per minute.



Standing at the ocean end of one of the Seabrook Plant's 19 ft diameter cooling water tunnels, a site geologist examines one of three intake shafts that will feed water into the tunnel.

Comanche delayed

DALLAS—Texas Utilities Co. said the estimated fuel load date for the Comanche Peak-1 nuclear plant has been delayed six-months to mid-1984.

The utility also said the estimated plant cost has been revised upward from $3.44 billion to $3.89 billion.

Texas Utilities cited final construction, inspection and activities relating to testing as the main resaons for the changes in estimates. The utility said construction is basically completed, but painting, electrical cables, documentation, final inspection and testing activities are taking more time than previously scheduled.

The utility announced that because of an excess of generating capacity, the lignite-fueled Twin Oak-1 plant will now be planned for service in 1989. It was originally scheduled for service in 1988.

Iowa utilities begin central dispatch

DES MOINES, IA—Five Iowa electric utilities have approved the formation of a partnership to operate a common dispatch control system, said Iowa Power & Light Co. President James R. Lyon.

He said the group will consist of IP&L, Iowa Electric Light & Power, Iowa-Illinois Gas & Electric Co., Iowa Public Service and Iowa Southern Utilities.

An interim control center will be operational this month in Des Moines. The site for the permanent center will be picked in 1985 after initial operating data from the interim center is analyzed.

"The single control center will allow customers to realize savings of the most economical electric generation to the extent that it is not fully utilized by the owners," said Lyon.

NOTE

ONLY THE FOLLOWING PAGES OF THIS
PUBLICATION HAVE BEEN FILMED

Cov. 1, p. 2, 14-17, 24.

3/1/84
C8650-4A

09325 1957257 * 2 2021
JOSEPH MCNALLY
CONGRESSIONAL INFO SERVIC D
4520 EAST WEST HWY STE 800
BETHESDA MD 20814

Volume 62, Number 3
March 1984

Electric Light & Power

THE NEWS MAGAZINE OF ELECTRIC UTILITY MANAGEMENT AND TECHNOLOGY

LP&L, Waterford-3 get passing marks in audits

BATON ROUGE, LA—Two independent consultant studies addressing Louisiana Power & Light Company's management capabilities and construction cost efficiencies for the company's nearly-completed Waterford-3 nuclear plant contain conclusions generally favorable to this southeastern utility.

Both studies were ordered by the Louisiana Public Service Commission following a rate increase request filed by LP&L early last year.

Arthur Young & Company conducted a management audit of LP&L and Decision Management Company, Inc., investigated the cost increases of Waterford-3.

The Arthur Young study found that LP&L, assisted by its Systems Fuels division, has been able to purchase low-cost fuel oil and natural gas. The consultants also concluded that the company had extracted from its workforce an acceptable level of productivity and, in general, operating costs were monitored and controlled in an efficient manner.

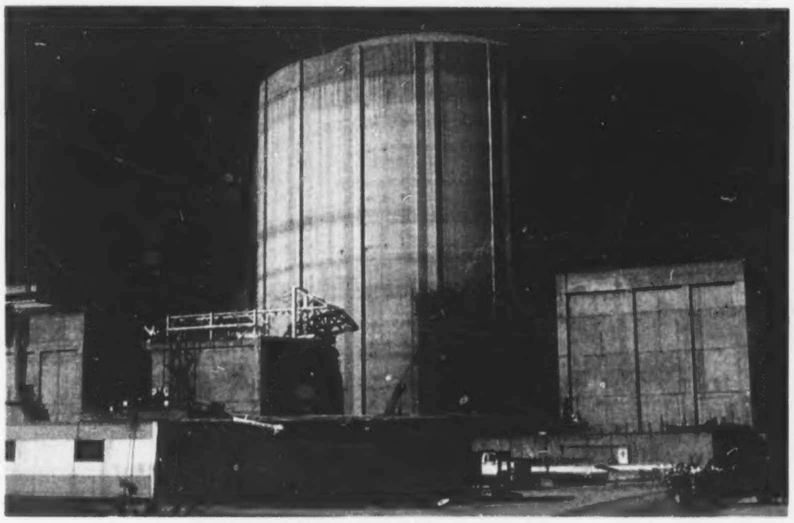
LP&L received passing marks for the manner in which it secured contracts and the Young investigators said they were convinced that the company had very capable people in its load forecasting and system planning areas. Recruitment policies and management salary levels were also approved by the consultants.

Waterford expenditures prudent

The Waterford-3 economic study concluded that while the total estimated cost of the plant ($2.65 billion), could not be termed "reasonable" in absolute terms, it was below the average cost of other nuclear plants built during the same period.

"The cost was primarily due to circumstances beyond LP&L's control, reflecting the difficulties of constructing these plants during the 1970s and early 1980s," Decision

Continued on page 13



The Waterford-3 plant costs less than other nuclear plants of the same generation, a consultant's study reports. Another study ok'd LP&L management practices.

Zimmer nuclear plant killed; coal unit eyed

Dan Utroska
Associate Editor

One of the most contentious and industry-crushing chapters in the history of the American nuclear power plant construction program has finally ended: the Zimmer nuclear plant has been terminated.

The announcement on January 21 by Cincinnati Gas & Electric, Dayton Power & Light, and Columbus and Southern Ohio Electric that they would discontinue all efforts to license the 810 MW plant marks the first time in U.S. nuclear power experience that a unit has been virtually completely built and then a decision made not to license the plant.

"We will be filing with the Atomic Safety and Licensing Board, in the near future, the appropriate legal papers for withdrawal of the application" for an operating license for Zimmer as a nuclear station, William H. Dickhoner, CG&E president and chief executive officer wrote to administrators at the Nuclear Regulatory Commission's Region III office in Illinois.

At the time of cancellation, the participants had invested $1.6 billion in the plant and it had been estimated that at least another $1.5 billion would have been necessary to complete the plant in accordance with NRC license requirements.

Zimmer, originally expected to be operational in 1975 for a cost of $240 million, has been plagued by charges of serious construction and quality assurance deficiencies. In November, 1982 the NRC stopped all safety-related work, pending an independent review of the licensee's management capabilities. Although the participants were able to get approval for one of their proposals for removing the NRC construction prohibition, two other plans—one to verify the quality of construction and another dealing with continuing construction—were under agency review when the utilities decided to end efforts to license Zimmer as a nuclear plant.

Conversion to coal?

In its announcement that it was ending any further construction expenditures on Zimmer as a nuclear facility, the participants said they had reached agreement to convert the power station to a coal-fired unit. However, short of the general statement that preliminary studies conducted by each of the participants indicated conversion to coal would be technically feasible and cost effective, no specifics on the conversion were available.

Asked what fraction of the current $1.6 billion investment in the nuclear unit would be applicable to the coal plant, CG&E spokesman Steven Brash said, "At this point we don't have a specific number on that."

Asked if it had been determined which nuclear components might be usable in a coal plant, Brash answered, "Not in specific detail." He mentioned, however, that the cooling tower, certain switchgear, auxiliary diesel generators, and some control elements could be used.

Brash said that an architect-engineering firm will be retained to determine the specifics of the economics and technical aspects of the conversion.

A week after its initial announcement, the three participant companies issued a press release declaring in part, "A great number of questions have been asked about the companies' plans. While we appreciate the interest in obtaining answers to these questions, a preliminary release of further information at this time would not serve any useful purpose. At some point in the near future when these engineering studies and cost evaluations have become more definitive, we will make appropriate information available."

Under the agreement-in-principle reached among the parties in the coal conversion plan, CG&E will purchase a larger share of the project from the other participants and will assume a correspondingly greater share of the associated costs. CG&E's ownership will be increased from 40 percent (its share of the Zimmer nuclear project) to 46.5 percent.

Dayton Power & Light's share will decrease from 31.5 to 28.1 percent.

Continued on page 11

More research needed

Reagan unveils acid rain plan

Don Minner
Assistant Editor

WASHINGTON, D.C.—After listening to both sides of the acid rain debate from his top advisors, President Reagan has decided that more research needs to be done before potential costly emissions control programs are mandated.

In his State of the Union Address in January, the President said he was going to increase the Environmental Protection Agency's (EPA) research budget from $28.8 million in fiscal 1984 to $55.5 million in 1985. The decision was somewhat of a surprise because EPA Administrator William Ruckelshaus had lobbied hard for a limited emissions control program involving 10 states.

When Ruckelshaus was sworn in last May, Reagan told him that acid rain should be his "top priority."

Throughout last year, pressure mounted on the administration to do something about acid rain. A number of scientific groups published studies suggesting a link between acid rain and sulfur dioxide from power plants. Also, the Canadian government and many U.S. politicians called for immediate emissions control programs. Fifteen bills were introduced in Congress calling for controls.

The National Acid Precipitation Assessment Program, a federal task force of scientists studying acid rain, said last summer that the major contributor to acid rain deposition in North America is probably man-made pollution. However, the scientists also cautioned that no exact link can be made between specific emissions and acid rain patterns.

Research pace quickens

Gary Foley, the EPA's top scientist in the group, told *EL&P* (Jan. 1984, p. 8) that the pace of the government's research program is increasing. He said that within five years, scientists will be able to specify what emissions need to be reduced to control acid rain.

Continued on page 2

Foreign Power Briefs

- **France, Britain, West Germany, Italy, and Belgium** have signed an agreement to share fast-breeder reactor technology, reports the *Wall Street Journal*. The Netherlands is expected to join the agreement later in the year. Officials of Great Britain say the group has no current plans for joint construction of a fast-breeder reactor, however.

- **The Japanese government** has decided to allow nuclear power equipment to be sold to China, with the condition that Peking not use it for military purposes. *Mainichi Shimbun*, a Japanese daily newspaper, reported that the decision was made at a December meeting of the Foreign Ministry, the Ministry of International Trade and Industry and the country's Science and Technology Agency.

- **Babcock & Wilcox Canada** said it will supply eight nuclear steam generators for the first two 600 MW CANDU reactors owned and operated by Intreprinderea Nuclearo-Electrica Cernavoda of Romania. In addition, B&W Canada said it will train Romanian office and shop personnel in the manufacturing process and will eventually provide consultants to Romania for future domestic supply. The $50-million contract became effective in mid-January.

- **Atomic Energy of Canada Limited (AECL)** said it has licensed Pacific Nuclear Systems Inc. of Washington to market its dry-storage concrete cask technology. The cask is designed as a passive system capable of accepting light water reactor irradiated fuel, five years or older, utilizing readily available construction materials. The casks have been in use at AECL's Whiteshell Nuclear Research Establishment since 1976.

- **AECL** and the New Brunswick Electric Power Commission have notified the Atomic Energy Control Board that they plan to engineer and build a second CANDU 600 MW reactor at Point Lepreau, southwest of St. John, New Brunswick. In 1974, the board approved the site for two CANDU units.

- **The Canadian Nuclear Association** reports that from Oct. 26 to Nov. 15, last year, the Gentilly-2 nuclear unit of Hydro-Quebec was shutdown because of the illness of a single shift supervisor. It seems that the problem developed from a requirement that the utility's supervisory personnel speak French. Since the shift supervisor was the only one that was qualified, when he became ill, the plant had to be shutdown. Now, reports the association, two more shift supervisors are currently being trained.

- **Sweden's State Power Board** says it wants to build a 1,200 MW coal-fired plant in the Baltic Sea port of Oxelosund. The government is evaluating a comprehensive environmental impact report and project proposal. In addition to the power plant, plans call for enlarging the port so that it can handle 7.7 million tons of coal a year by 2000. *Sweden Now*, an international magazine promoting the country, reports that the plant may run into difficulty. The magazine says the power really isn't needed and the plant wasn't designed so that cooling water could be used for district heating. Both problems irritate the government, said the publication.

- **Mexico's** national electric utility agency, Comision Federal de Electricidad signed a power exchange agreement with Southern California Edison Company. The agreement will enable either utility to buy electricity from the other whenever the price is lower than the cost of producing the same electricity at its own power plants or purchasing it elsewhere.

In This Issue

Editorial 4

Calendar 9

Life extension programs for aging power plants are getting serious attention from the utility industry 14

Heat rate improvements for existing plants and the next generation of new fossil-fired plants are targets of a new EPRI program.**G** 24

A computer program for buying and selling power is helping San Diego Gas & Electric optimize its energy interchange.**T/D** 34

New Products 37

Readers' Service 39

Bulletin Board 40

Regulatory Review 43

Personnel 44

Management Methods 46

EL&P readers whose responsibilities include both Generation and Transmission/Distribution receive both technology sections. Other readers receive the technology section that applies to their respective area of responsibility. The Generation edition is indicated by a single dot (•) in the upper right corner of page 1; the T/D edition carries two dots (••). All readers receive EL&P's industry news section.

Rural America threatened by Reagan, warns NRECA head

SAN FRANCISCO—Policies of the Reagan administration "pose the greatest threat to agriculture and rural America that we have faced since the Great Depression," warned the head of the National Rural Electric Cooperative Association (NRECA).

Speaking before approximately 10,000 attendees of the NRECA annual meeting, Executive Director Robert D. Partridge said he saw no way to reconcile the views and convictions of rural electrification leaders with those of the administration "whose ideas faithfully track the 1981 OMB budget blueprint for phasing out the REA program."

President Reagan has opposed legislation supported by the group that seeks to raise interest rates on loans to rural electric systems, provide them with a permanent source of capital through the Rural Electrification Administration and permit the rural electric systems to refinance loans if interest rates drop.

Bipartisan support

Partridge said that there is strong bipartisan support in Congress for the rural electric financing legislation and he predicted that the bill would be passed.

"You have the fight of your lives ahead to protect the rural electrification program, revive rural development, and obtain decent farm credit and farm income programs," he told the rural leaders, "You had better gird for battle."

The NRECA head also reviewed the strengths and challenges of the rural electrification program.

He said, "We have derived great strength from the fact that we are non-profit systems, principally cooperatives, dedicated to service. Each of us has no other purpose than to provide service. We do not have to compromise to other purposes...We are not miniatures of investor-owned utilities and we'd make a grave mistake if we were to presume that we are."

Partridge pointed out that the inherent disadvantages of serving rural America are still there—low density and high investment in relation to revenue.

Delegates cautioned

Delegates were cautioned by Partridge to be "watchful, discerning and member-responsive" as they debate and develop policies that will guide them in the years ahead on such matters as the environment, federal power and reliable power supply sources.

Partridge has headed the association since 1968. In April he will be succeeded by former Secretary of Agriculture Bob Bergland. NRECA's membership includes 1,000 consumer-owned rural electric systems serving more than 25 million people in 46 states.

Acid Rain . . . from page 1

In an interview with reporters the morning after President Reagan's State of the Union message, Ruckelshaus said that the President did not believe an acid rain program was currently justified.

"The President is not persuaded at this point that we know enough to implement a major sulfur dioxide emissions program," said Ruckelshaus.

Insiders say that Ruckelshaus couldn't garner enough support for his plan among members of the President's Cabinet Council. Budget Director David Stockman and Energy Secretary Hodel were known to be adamantly opposed to any type of control plan at this time because of multibillion price tags for a large cleanup.

EPA spokesman Chris Rice said there are no present plans for the agency to implement any emissions control program and that Ruckelshaus will fully support the President's position.

Others outraged

Environmentalists and Canadians were outraged by the call for more research.

"President Reagan ordering more research is akin to the captain of the Titanic ordering further measurements of the size of the holes before doing anything," said Dick Ayres, chairman of the National Clean Air Coalition.

Elizabeth Barratt-Brown of the Natural Resources Defense Council, an environmental lobbying group, said "Reagan is standing alone." She said the longer a control program is delayed, the greater the damage will be.

Brown said that the President has put the ball into the hands of Congress and she expects them to take some form of action on acid rain in the short time left in the term.

"Clearly, acid rain is one of the most pressing issues on Congress's agenda," said Barratt-Brown.

Canada's Environment Minister Charles Caccia said he was "shocked" by Reagan's decision to continue studying acid rain. For some time, Canadians have been pressuring Washington to do something about acid rain. They claim that Canadian lakes and streams are dying because of U.S.-originated acid rain.

Disappointed

"We are deeply disappointed by the failure of the United States government to take concrete action to deal with the problem of acid rain," stated Canada's Department of External Affairs.

Others, such as National Coal Association President Carl Bagge, disagreed. He said the President's decision displayed remarkable political courage.

"The President should be commended for refusing to yield to ill-advised demands for a multi-billion dollar program that will produce little or no benefit and for proposing direct action to deal with acified bodies of water," said Bagge.

Did You Hear...

"I can close my eyes and listen to somebody start to talk about acid-rain, and I can tell you within 100 miles where he or she lives." The clues: Westerners say they want acid rain cleaned up, but they won't pay for it. New Englanders say their lakes are poisoned and Midwesterners should pay for the cleanup. Midwesterners don't think there's a problem. And Southerners say, "It's your problem, don't bother us."

— EPA Administrator William Ruckelshaus on NBC News's "Meet the Press."

Can the utility industry find a fountain of youth for its aging generating capacity?

Robert Smock
Managing Editor

Utilities are beginning to get serious about power plant life extension. They've been talking for several years about spending money to extend the life of 30-year old plants another 30 years, but so far haven't committed much money to it.

Examples of pure life extension projects on old generating capacity are still few and far between, but the pace appears to be picking up.

If the trend develops it will be a significant change in the way utilities do business. Traditionally, fossil-fired capacity was retired when it was about 40 years old. Spending on aging power plants started to decline at about the 25-year mark as reliability deteriorated and such capacity was typically relegated to periodic operation, reserve status, and, ultimately, demolition.

Now utilities are thinking about spending several hundred dollars a kilowatt on old plants in order to get another 15, 20, or even 30 years of life. That's often more than the plants cost to build, but with new fossil capacity costing more than $1000 a kilowatt it might make sense.

Potomac Electric Power Co. recently announced that it plans to spend $79 million on extending the life of its 500-MW Potomac River station. Work has started on units 1 and 2, 92-MW each, which went into service in 1949 and 1950. Design goal for replacement component suppliers is 30 years more life.

"Because of high construction costs the company wants to defer for as long as possible the need to build new generating plants," said PEPCO president Edward Mitchell in announcing the project. "Plant life extension, along with our energy use management programs, will help us achieve this objective."

Most utilities considering life extension are still in the "study" phase. An example is Pennsylvania Power & Light Co. which hired Westinghouse to do a $1 million study of extending the life of a 343-MW unit at its Brunner Island station to the year 2010. Another example is Wisconsin Electric Power which hired Bechtel to look at extending the life of three units at a cost of more than $1 million per unit for the study.

Aging capacity

Life extension could become a significant trend in the industry in the '80s because of several underlying forces. One is the shift in average power plant age. Historically, only a tiny percentage of total utility capacity was a candidate for retirement. Exponential growth of 6 or 7 percent a year meant that half of all capacity was always brand new, less than 10 years old.

That pattern held until 1970. As shown in Table 1 half of all capacity in 1970 was less than 10 years old and only 2 percent was more than 30 years old. The slowdown in new capacity additions during the decade produced a slight shift in those percentages by 1980. However, by 1990 and 2000 there will be profound changes in the age characteristics of the U.S. power plant inventory.

For example, Westinghouse projects that by the year 2000 there will be almost as much 30-year old capacity as 10-year old capacity. Combustion Engineering's Mark Caron, manager of availability and reliability engineering, says this means that 694 coal-fired units, totaling almost 40,000 MW, will pass the 30-year mark in the next few decades. Of course, utilities could retire those old units but, for the first time in the history of the industry, the old units will represent a large and valuable asset.

Senior citizens

These senior citizens will be a large percentage of the total because of the new capacity addition patterns of the last 40 years. As shown in Table 2 growth in generating capacity spurted up sharply in 1950. Look at just the coal-fired plant column. During the 20's 2000 MW were added, 1500 MW in the 30's, 10,000 MW in the 40's, 50,000 MW in the 50's, and 100,000 MW in the 70's. The 50,000 MW added in the 50's, the first big block of capacity in the history of the industry, is just now approaching the traditional end of life and utilities must decide what to do with it.

TABLE 1
AGING GENERATING CAPACITY

Percentage of utility generating capacity that is:

	10 years old or less	More than 30 years old
1970	50%	2%
1980	45%	8%
1990*	30%	15%
2000*	26%	23%

*Assumes all currently planned plants are completed.
Source: Westinghouse

That pattern will continue into the future because utilities have cancelled so much of the capacity that was to have been added in the 1980s and 1990s. Since 1975 order cancellations have topped new orders by more than 50,000 MW. That's why new capacity will constitute a smaller percentage of the total inventory for the next 20 years and capacity more than 30 years will grow in importance.

In addition, that large block of old capacity is more valuable than 20's and 30's vintage capacity. It was in the fifties that average new unit size topped 100 MW for the first time in industry history and heat rates got down to the 10,000 range. Older capacity has relatively tiny unit sizes and heat rates approaching 20,000 in some cases.

It was easier to decide to retire plants that used obviously obsolete technology. The capacity now crossing the 30-year line is not obsolete. Efficiency and reliability of fossil-fired generating capacity has not advanced much, if any, over the past 30 years. In fact, old capacity burning high-sulfur coal without a stackgas scrubber may look attractive to some utilities compared to new capacity requiring a scrubber.

The overriding consideration, however, is cost. In order to continue to operate 30-year-old plants some refurbishing is necessary because, otherwise, the forced outage rate would rise rapidly. The cost of such refurbishment can be much less than the cost of new capacity.

Deferring new capacity

Potomac Electric Power Co. has committed to a strategy of power plant life extension in order to defer the need for new generating capacity. The utility has been surveying its older capacity for the past two years and recently announced a $79 million revamping of its Potomac River station. The station is PEPCO's oldest. It has two 92-MW units built in 1949 and 1950 and three 110-MW units built in 1954, 1956, and 1957.

Goal of the modernization project is to extend the units' life "as long as is economically and technically possible," says Bob Carelock, project engineer. The design goal that's being used is an additional 30 years, he adds. That's the number PEPCO gives suppliers who need a target. As a practical matter, the utility doesn't know how long the units can ultimately last, says Carelock.

The issue is economics. How much is worth spending. An equivalent amount of new capacity would cost PEPCO $635 million, so the $79 million (in 1983 dollars) for upgrading the Potomac River station was felt to be justified.

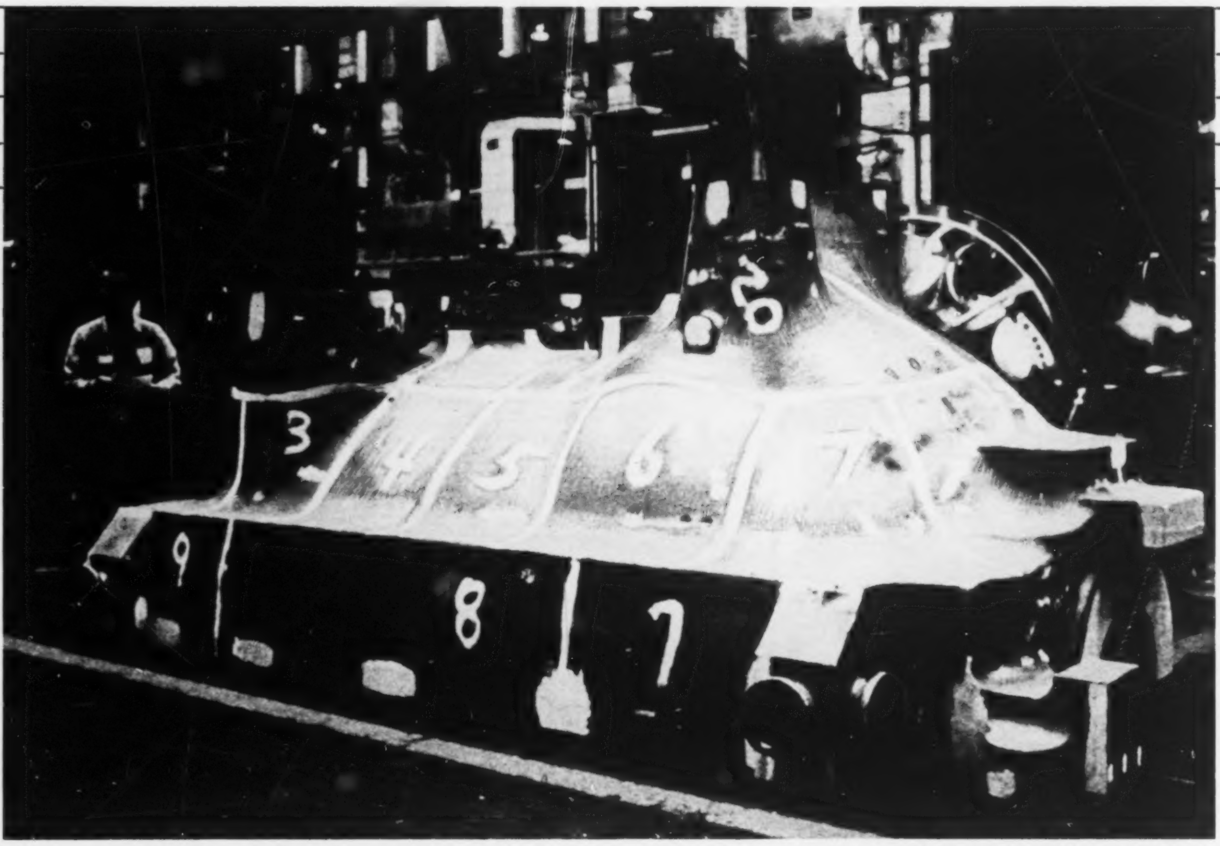
The work will be done in stages over the next 10 or 12 years. At each unit's annual two-month scheduled outage a portion of the work will be done. In January unit 1 was down for the first step of its rebuilding. Focus was on boiler work, including replacement of the high temperature superheater, tubular air heater elements, and the lower section of the economizer. Additional boiler work and replacements of other components will be done in future outages. In April the first stage of work is slated to begin on unit two.

Carelock explains that PEPCO has been surveying company capacity and studying the potential for life extension for the past two years. Company engineers have overseen the work but specific portions have been farmed out to the original equipment suppliers, Combustion Engineering on unit 1 and 2 boilers and GE for the turbine generators.

The inspections showed that several PEPCO stations are, or will be, candidates for life extension. Most of the refurbishing will be done on the boilers, as described. Some stations will need new pulverizers, outer turbine casings will have to be replaced in a few cases, and some generators will require rewinding. Carelock says control systems are still being surveyed with an eye to upgrading obsolete, decentralized systems that are unwieldy to operate and for which spare parts are no longer available.

The Potomac River station project is the first of its kind on the PEPCO system, says Carelock. Previous plant upgrading projects have been done to achieve a goal other than life extension—a balanced draft conversion project at the utility's Chalk Point station, for example. Next PEPCO candidate for life extension will probably be its Dickerson plant.

PEPCO expects system peak demand to grow at an annual rate of 1 to 2 percent for the next 10 years. Life



GE says a complete turbine shell replacement can be useful in a life extension project because modern designs have a lower cracking rate.

extension is expected to put off the need for new capacity until the mid to late 1990s.

Studying life extension

Pennsylvania Power & Light is an example of a company that's seriously considering life extension but hasn't yet committed to a large capital program. Given less-than-forecasted load growth, a nuclear station in the final stages of construction, and healthy reserve margins, management decided that the utility should not commit to any new generating capacity for the indefinite future. In order to provide insurance, a formal program to protect existing capacity and extend its life was launched.

Tom Yezerski is manager of the fossil plant extended life program at Pennsylvania Power & Light Co., a job that didn't exist at his company until 1982, and still doesn't exist at most utilities. "We don't have a lot of data yet, but compared to other utilities who aren't sure they want to do this, we're ahead," says the manager.

No major renovation projects have been started yet, but Yezerski feels that an investment as high as $1000 per kW might be justified.

First step in the program was a "health exam" for all the utility's generating stations. Goal is a prescription of actions to take to achieve the desired effect, which ranges from extending the plant life indefinitely to improving plant efficiency, raising output, or converting it from base load to cycling operation.

Most of the checkups are being done in-house, but one, at the utility's Brunner Island station, was farmed out to an outside contractor, Westinghouse, as a test case. Yezerski said Westinghouse was asked for recommendations to extend the life of one 343-MW unit at the plant to the year 2010 and to change its duty cycle so it could turn down as low as 50 MW on a daily basis.

In a preliminary report Westinghouse said it would cost $32 million to achieve both goals and $20 million for the life extension alone. Westinghouse concentrated on the turbine generator and brought in Combustion Engineering to look at the boiler. New equipment such as a high-pressure turbine casing and a new boiler roof were recommended. Yezerski points out that the unit is now running fairly well and there is no immediate need to renovate it. The purpose of the Brunner Island study and the in-house studies is to assess where the utility is right now and plan the future in a systematic way.

As at most utilities Pa P&L has always had an active maintenance and betterment program for its existing plants, Yezerski explains. The utility has currently committed to a total of $43 million worth of such projects, a combination of maintenance and upgrading at most of its plants. Some of these projects, such as renovating boilers at two 130-MW units and an 80-MW unit, could fall under the life extension program. There's still a lot of overlap.

Yezerski explains that the new program is not intended to be traditional maintenance and that part of the learning process is to determine how to treat capitalized upgrading and life extension projects differently from conventional, expensed operation and maintenance projects.

So far the life extension survey at Pa P&L has identified $118 million in 55 projects at 14 steam plants and 12 hydro plants totaling 4500 MW. None of these has been committed yet. Yezerski says the utility is not close to a commitment to a major renovation. For one reason, it doesn't have to, and there are too many unknowns remaining. "It's not just a simple economic decision," he adds.

Another utility that's doing formal studies is Wisconsin Electric Power. The company is spending "more than $1 million per unit" for life extension studies by Bechtel. The focus is on typical units at each of its three old coal-fired stations, reports operations vice president Ken Walters. The studies are being done on the 80-MW, 1948-vintage Port Washington unit 3, 120-MW North Oak Creek unit 1 (1953), and a 250-MW, 1959 vintage unit at its South Oak Creek station.

Milwaukee-based WEPCO is in a situation of uncertain load growth, a fairly large reserve margin, and a capacity expansion program ending in 1985 with the completion of the 600-MW Pleasant Prairie unit 2. Questions to be answered in the life extension study, says Engineering Vice President Huberto Platz, are, Is it feasible to extend the life of typical units at these stations to 2010? and, What would be required and what would it cost? Future capacity expansion plans will depend, to some extent, on the results of the life extension studies.

WEPCO's experience gives some insight into a utility's retire/renovate decision. The company recently retired its 1920's-vintage Lakeside station which had 350 MW spread over 14 oil-fired units, none larger than 60 MW. Fuel cost and manpower cost of continued operation of that plant were felt to be prohibitive, so it was retired, relates Walters. At the other end of the spectrum is the utility's Valley station with two 136-MW coal-fired units. Since they were installed in 1968 and 1969, there's no need to consider them for life extension.

WEPCO hired Bechtel to do the studies, says Walters, because it wanted a plant-wide, systems approach: "We could have gone to equipment vendors but we felt a firm like Bechtel has a broader knowledge of combined systems. It's more than just individual components. We're interested in the whole system." The study started in May, 1983. The investigative phase is complete and preliminary findings are now being presented. Final report is due in late June of this year.

Still building nukes

Even utilities in the middle of large nuclear construction programs are looking at life extension. Duke Power Co. has conducted formal surveys of two stations with 30-year old units (Dan River and Allen) by its own engineering staff. Duke is still in the middle of a nuclear construction program. Its McGuire unit 2 is slated to go into service this spring and two units at the Catawba station are under construction and scheduled to go into service in 1985 and 1987. That, however, is the end of the company's construction program and it wants to make sure that it is taking any necessary steps now to insure that loads will be met in the late 80s and 90s. Duke is still evaluating the studies and has not committed any capital to life extension projects.

Gas-fired capacity

Life extension appeals to different utilities for different reasons. Consider Oklahoma Gas & Electric, a utility that hasn't committed any money to life extension, but is thinking seriously about it.

Traditionally a gas-fired utility, OG&E began a coal-fired, base-load plant construction program 10 years ago and now is about half and half. Its gas-fired capacity was threatened by the Carter Administration's Fuel Use Act which said utilities would have to shut down base-loaded gas-fired capacity by the 1990s. That federal law was repealed however, and now OG&E is looking at its gas fired capacity in a new light.

Some utilities with gas-fired plants are opting to convert them to coal (Tucson Gas & Electric, for example) or replace them with new coal-fired plants and shut them down. OG&E, however, is located in the middle of the gas supply region and utility executives are confident that they know how to buy gas and keep it relatively inexpensive. Chairman James Harlow said, in an interview last fall, "I think we'll be burning gas into the next century if we can keep those units running. We're studying the possibility of life extension of those gas-fired plants."

OG&E Vice President Merril Hines said that life extension of gas-fired capacity will probably be cost-effective. Goals of an upgrading program would be to convert gas-fired capacity to handle intermediate, cycling-type duty, to restore original heat rates, and to extend plant life. First candidate may be a 30-year old, 74 MW unit at the utility's Arbuckle power plant.

The modernization project would have to prove cost-effective compared to buying new peaking/intermediate generating capacity at about

$300/kW, Hines explained. He added that there are some non-cost factors in favor of refurbishment. For example, federal law restricts new gas-fired generating capacity to 1500 hours of operation per year. A modernized existing plant would have no such limit. Also, a new plant would require a costly and time-consuming siting process while the old plant is already on an approved site.

Hines said that a decision will have to be made for capacity that is about 35 years old, the expected life for OG&E plants. "If you don't do something," he explained, "you know that you'll be getting close to the life of some components in the plant. We don't feel we can continue to operate the old plants and consider them dependable capacity."

Not all OG&E's gas-fired plants are candidates, explained Production Vice President George Gibbons. Some are just too old or have special problems. For example, the utility retired its Belle Isle peaker plant because an environmental restriction on cooling water temperature limited its operation to winter months. Another plant, the Osage station was retired because it had an average heat rate of 17,000. That was OK when gas cost 18 cents a million Btu, but at today's prices, said Gibbons, "You can't stand that." Two other units of 1928 vintage, Muskogee 1 and 2, also had heat rates too high to warrant rebuilding them.

Gibbons says OG&E's Arbuckle station is a good test vehicle for the concept of life extension. It is not too small or too old, so OG&E hired a consultant to make a study. "We're approaching it very cautiously," says the executive.

Funds are available

Another utility that's committed to protecting its investment in existing generating capacity and extending its life is Virginia Electric & Power Co.

Power station Engineering Vice President Bill Spencer explained management's philosophy at last fall's Joint Power Generation Conference. "Funds are available and people are available" for work on the older power plants because other major capital projects are finished.

"We've completed a nuclear program—we built four and cancelled four," Spencer explained. A costly program of replacing steam generators at one nuclear station has also been finished. The next step was to reduce the company's reliance on oil fuel through a massive coal conversion program that is now largely complete. As a result of this activity rates have been relatively flat for the past few years, and VEPCO management wants to keep it that way.

Concentrating on maintaining or improving the operating performance of the existing capacity is perceived as the best way to continue to hold rates down at VEPCO. Some modernization projects on old capacity have already been completed. For example, two units built with forced-draft boiler systems whose performance was not good have been converted to balanced draft. Two more are being converted.

Spencer said VEPCO currently has 300 retrofit and improvement projects under way at nuclear and fossil plants. The projects are keeping 460 engineers busy, 300 of them VEPCO's.

How are projects picked? Spencer says VEPCO started out by doing payback analyses, but quickly moved beyond that. Under the utility's rate structure most of the benefits of efficiency or output improvements flow through to the customer in the form of fuel cost adjustment reductions.

TABLE 2
MEGAWATTS OF NEW U.S. CAPACITY

	Unit Type						
Years	Coal steam	Gas steam	Hydro	Lignite steam	Nuclear	Oil steam	Total*
1900-1905	0	0	116	0	0	0	126
1906-1910	0	0	507	0	0	14	521
1911-1915	0	6	850	0	0	86	942
1916-1920	72	191	865	0	0	439	1,582
1921-1925	676	376	1,778	0	0	556	3,452
1926-1930	1,303	927	2,432	10	0	1,533	6,305
1931-1935	241	119	871	8	0	942	2,411
1936-1940	1,308	532	2,677	12	0	1,287	6,134
1941-1945	2,942	617	2,885	0	0	2,344	8,920
1946-1950	6,714	3,130	2,372	122	0	6,176	19,140
1951-1955	24,123	5,811	6,319	88	0	11,376	48,147
1956-1960	25,738	8,908	8,922	105	287	12,602	57,016
1961-1965	23,341	8,301	12,159	151	566	15,359	62,474
1966-1970	43,076	17,084	6,997	619	4,905	10,186	96,754
1971-1975	55,918	16,550	4,963	3,178	30,789	20,665	161,938
1976-1980	52,766	2,942	8,925	5,943	17,042	15,382	113,674
1981-1985	53,843	0	2,666	6,530	49,398	2,892	126,332
1986-1990	21,075	0	68	1,560	30,615	444	58,122
1991-1995	1,100	0	0	0	8,526	800	10,696
Total	314,236	65,494	66,372	18,326	142,128	103,083	784,686

*Total includes combined cycle, gas peaking, internal combustion, and pumped hydro, which are not shown.

Source: DOE

TABLE 3
AVERAGE AND WEIGHTED AVERAGE AGE

Type of unit	Number of units	Total capacity (MW)	Average age (years)	Weighted average age (years)
Coal steam	1,352	255,197	23.6	13.2
Oil steam	794	99,175	28.9	17.9
Gas steam	683	63,708	27.4	17.4
Lignite steam	38	11,382	16.9	5.9
Nuclear	91	72,736	7.2	5.8
Combined cycle	86	6,788	8.8	7.5
Oil peaking	839	31,199	11.2	10.2
Gas peaking	208	6,453	11.7	9.7
Internal combustion	2,302	3,922	27.2	22.1
Hydro	2,642	64,768	45.7	24.1
Pumped hydro	130	14,436	11.4	8.1

Source: DOE

"Cost-benefit analysis is not possible on all projects," said Spencer. "You just have that gut feeling you should do it." Capital investments are justified, even if returns don't flow straight through to the shareholder, if they can serve to hold down rates, Spencer added.

Equipment suppliers

Major equipment suppliers are encouraging the life extension trend because it provides them a market for goods and services in the absence of a new plant market. Westinghouse, for example, has been marketing turbine-generator upgrades for several years and now has launched a comprehensive plant modernization program. "Utility managers' desks are piled high with proposals for modernization of individual pieces of equipment," says T-G division Marketing Manager Kenneth Oleson.

In order to develop a total plant approach that would be more welcome to utility executives, Westinghouse intends to join forces with A-Es and boiler suppliers. As mentioned above, the first such study, with Combustion Engineering, was done for Pennsylvania Power & Light Co.'s Brunner Island station. The utility is now evaluating it.

The modernization work Westinghouse has been doing on turbine-generators for the past five years or so has been focussed on converting from base-load to cycling operation. The trend now is pure life extension of the entire plant, says Oleson. For the next year or so the utility industry will continue doing studies and capital spending should begin in a major way in 1985 or 1986, Oleson guesses. "They're going to want to feel comfortable about our ability to accurately predict the life of components and extend the life of the plant."

The goals of a Westinghouse plant modernization project are to extend the life of a plant another 20 or 30 years, says Oleson, and to improve plant performance. Performance guarantees are part of the package, he adds. Secondary benefits include improved plant availability and factors like changing the plant from base-load to cycling.

Oleson says the potential utility market over the next 10 years for turbine island modernization alone is $10 billion.

Power plant life extension also represents a huge potential market for boiler suppliers. Norman Freeman, director of maintenance engineering and repair for Foster Wheeler, sees boiler "aftermarket" business doubling over the next few years. Right now utilities are showing interest in major boiler life extension studies, says Freeman, but they're spending money on fairly conventional maintenance services. Foster Wheeler is seeing an increase in its annual contract power plant overhaul business. This is long-term, pre-planned maintenance, Freeman explains.

"There are a lot of studies and a lot of talk about extending the life of power plants," says Freeman, "but utilities aren't spending a whole lot yet." Foster Wheeler is currently doing the boiler inspection on Wisconsin Electric Power Co.'s Oak Creek station.

With new fossil capacity costing $1200 to $1500 a kW, it may make sense for utilities to spend a few hundred dollars a kW on old capacity to upgrade it to its original capacity or improve it with new hardware and technology, Freeman says. He notes that this work can be done quickly, usually in less than one year, allowing utilities the luxury of putting off a decision on life extension until load-growth trends and capacity expansion plans become clearer.

TVA life extension

Foster Wheeler has already completed a major boiler upgrading job at TVA that could be included in the life extension category. The job was done on four 150-MW coal-fired units at the Johnsonville station. TVA decided to rebuild the boilers of these 25-year old units because a predicted boost in availability led to a capital cost payback time of only 4.5 to 5 years, according to utility engineer Charles Dammann. Life of the boilers was also extended an estimated 15 years.

Availability deterioration was the main reason for the Johnsonville upgrade. Between 1960 and 1972 availability at the four units average 90 percent. Between 1973 and 1976 it dropped to 81 percent. TVA and Foster Wheeler, which supplied the boilers, then did an inspection and engineering study that determined that a boiler rebuild could solve the problem. The rebuild started in the spring of 1981. Each unit was scheduled to be out of service for 26 weeks. The job was completed last April. Since then forced outages were "nil" and there's been a "substantial increase" in availability and reliability, according to TVA and Foster Wheeler.

Costly new capacity

Economics is driving the life extension trend, according to Combustion Engineering's Mark Caron. Today's 30-year old capacity cost only $100/kW to build, he pointed out at the Joint Power Generation Conference. New coal-fired capacity now costs $1200-1500/kW. New capacity also faces siting and environmental problems that can be sidestepped with rebuilt existing capacity.

CE's analysis of aging power plants shows that plants, boilers in particular, enter a "wear-out" phase in which component failure rates climb sharply. The goal of a life extension program is to eliminate that phase.

H. Kerner Smith, manager of fossil power systems for Babcock & Wilcox's utility power generation division told the conference that 60 percent of the fossil units in the U.S. are more than 20 years old. Many of these units are or will be used for cycling duty. Said Smith, "These units weren't designed to do what you're doing to them." Boiler suppliers see an opportunity to upgrade this capacity for cycling operation. Right now utilities seem to be waiting, to finish their existing capacity expansion programs, to see how much acid rain regulations cost them, and to watch load growth.

Smith said B&W work on old plants has included fuel conversions, cycling

Continued on next page

Life extension . . . from page 16

modifications, boiler pressure part replacements, and capacity restorations and half a dozen coal-fired plants that switched to lower-grade fuels. Starting point is a boiler fitness survey, a "health scan" of boilers.

Riley Stoker Co. has also been active in the business of modernizing old boilers. Examples of the firm's recent work are installation of new superheater and waterwall tubing at Texas Electric's 20-year old Handley unit 3, replacement of waterwall panels at PEPCO's Dickerson station, and superheater modification at Texas Electric's 20-year old generating Graham station.

Control systems

Control system modernization is a popular specialized form of upgrading at power plants. Frank Ryan, applications engineer for Leeds & Northrup, says that utilities with obsolete control systems are prime candidates. There are many power plants with controls supplied by companies that have gone out of business or using hardware that is no longer available. Utilities are unable to maintain these systems or even buy spare parts.

That obsolescence, plus the new distributed digital technology that is sweeping in, has led many utilities to tear out the old and put in completely new systems. Modernization is a very active business for controls suppliers, says Ryan. "It's virtually the only business there is right now," he adds.

Some of the projects are part of larger, comprehensive plant upgrading projects but many utilities are focussing in on just the control systems in old plants they want to operate longer.

Ryan describes a control system upgrade project recently completed at LILCO's 10-year old Northport unit 3. An analog combustion control system was replaced with an L&N microprocessor-based digital control system.

L&N has a project currently underway at Philadelphia Electric's 20-year old Eddystone and 30-year old Cromby stations. Eddystone has an old hydraulic control system for the feedwater heating cycle that is being replaced in the first phase with a digital system.

"Virtually all modern control systems wind up digital," says Ryan. Utility operating people start out talking analog electronic because there is generally "not a positive perception" of anything digital, he explains. But when they look at the new control technology and the results it's achieved, at installations such as LILCO, they are convinced to go with digital microprocessor-type controls.

Ryan points out that new plants and modernization projects are still going in with analog controls, but that's because the control system commitment was made before the microprocessor revolution of two or three years ago. The newer units are committing to distributed digital controls. L&N just shipped digital hardware for New York State Electric & Gas Co.'s new Somerset station. Another customer, Northern States Power committed to distributed digital control for its Sherburne 3 unit.

"Everything we've bid in the last two years has been microprocessor-based DDC," says Ryan. Buyers may start out talking analog but "when the chips are down" and they have to make a commitment, they're going distributed digital.

The new technology is helping the modernization business because it allows utilities to do things not possible 20 years ago due to hardware limitations, says Ryan. For example, automatic load control can be improved substantially. In many old power plants the response of the unit to command pulses sent by the dispatcher is unpredictable. The unit may change load at the intended rate, it may not change at all, or may change too fast, says Ryan. New hardware can close that loop at the power plant and make it much more reliable. There are major benefits in economic dispatch, says Ryan, at a control system cost that's "not that great."

First look taken of TMI-2 core samples

MIDDLETOWN, PA—Preliminary examinations have been conducted on the first samples of the damaged TMI-2 fuel core, said GPU Nuclear.

Radiation measurements from two of the samples produced readings of one rem an hour, gamma, at a distance of one ft from one of the samples and five rem an hour, gamma, on contact from the other, said GPU.

Last fall, six samples were taken from two locations in the core. One was at the center and the other at a point midway between the center and the core's edge. At each point, a sample was taken from the rubble bed surface and at depths of two inches and 22 inches below the bed's surface.

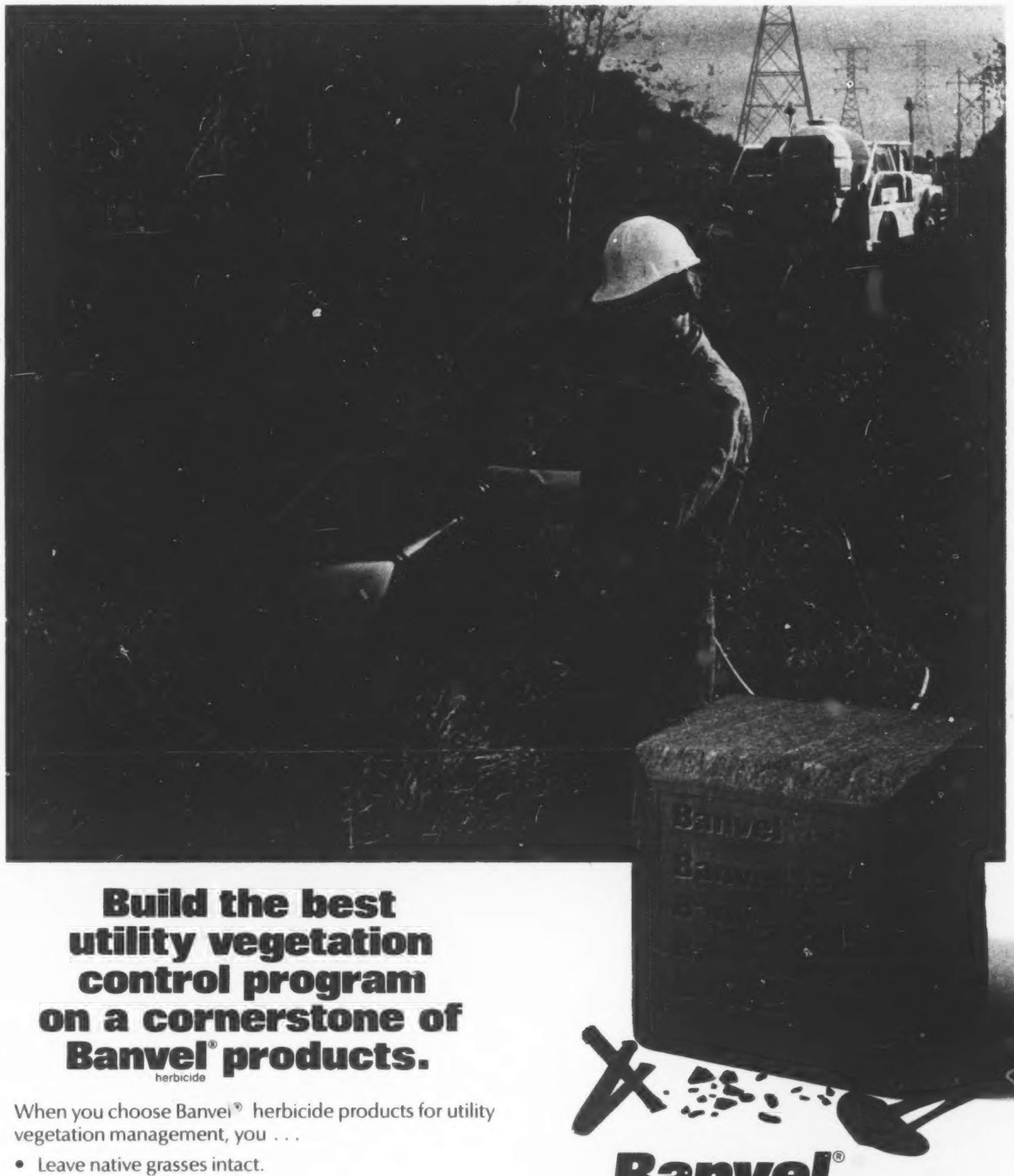
GPU Nuclear said the samples ranged in size from particulate matter less than four one-hundredths of an inch in diameter to "rock-like" pieces six-tenths of an inch in diameter. This means, explained the company, that plans to remove a majority of the core with vacuuming equipment can be carried out.

The larger pieces help to confirm the utility's belief that the rubble bed was created when overheated fuel assemblies shattered after being suddenly cooled by water. The sample particles are mostly brown and black, said GPU.

The samples also gave GPU Nuclear further proof of the melting of some stainless steel components and other metals with lower melting points. Stainless steel has a melting point of 2,550 Farenheit to 2,600 F. The utility said its preliminary examinations have produced no evidence of melted uranium oxide fuel, which melts at 5,080 F.

Additional examinations

Additional examinations to obtain further information on the radiological and chemical nature of the debris samples will take several months to finish, according to the utility.



Build the best utility vegetation control program on a cornerstone of Banvel® products.
herbicide

When you choose Banvel® herbicide products for utility vegetation management, you . . .

- Leave native grasses intact.
- Get cost-effective results.
- Spray materials that are environmentally sound when used as directed.
- Control the broadest spectrum of broadleaf weed and brush species.
- Choose from a wide variety of approved tank-mix options.

Talk to your Velsicol representative and find out why Banvel herbicide products are the best way to build utility vegetation management programs that fit all your needs.

Banvel® herbicide products.
Your cornerstone of vegetation management

VELSICOL™
CHEMICAL CORPORATION

Banvel® is a registered trademark of Velsicol Chemical Corporation
Read and follow label directions carefully

Inquire R.S. 6

Operating unit heat rates can be cut, says EPRI; new units can be 10% more efficient

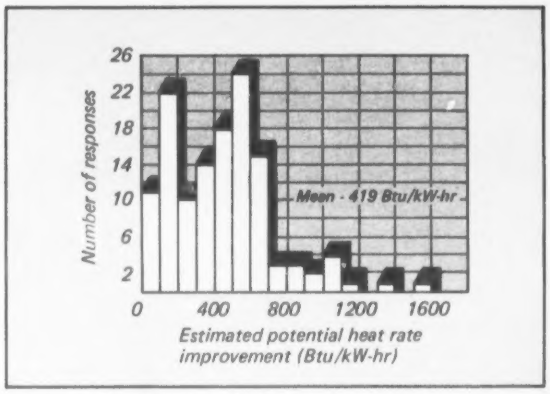


Fig. 1. Survey of heat rate improvements.

Robert Smock
Managing Editor

A one percent improvement in the heat rates of many existing fossil-fired plants is "easily attainable," according to EPRI's manager of power plant systems and performance, Tony Armor. Fuel savings over the next five years resulting from such a gain would be worth $700 million.

Armor focussed on heat rate improvements in a presentation at last fall's Joint Power Generation Conference on EPRI's programs to improve the performance of existing plants.

"New plants, nuclear or fossil, will be few and far between until the year 2000," Armor said, adding, "That increases the importance of operating the existing ones." He pointed out that there are 1000 fossil-fired units in operation that are 100 MW or larger in size. The developing trend to extend the life of some of these aging plants (see related story beginning on page 14) should include an effort to improve heat rates, Armor said.

Room for improvement

That's because there's so much opportunity for improvement. Looking at fossil system heat rates, Armor said, "There's a huge disparity between the best utilities and the worst." Displaying *EL&P's* list of the 20 most efficient units operated by the 100 largest investor-owned utilities as shown in Table 1, Armor said the performance of Duke Power's Marshall station can serve as a benchmark for other utilities.

He said the goal of EPRI's programs is to achieve a 3 percent gain in the performance of older units.

One incentive for effort in this area is growing pressure from state regulators. Armor claimed that all but 15 PUCs have added power plant operating incentives, in the form of rate penalties, for factors such as heat rates, availability, capacity factors, and forced outage rates. This trend developed in the last few years.

He reported results of a survey that shows utilities feel they can get a substantial improvement in their existing units' heat rates. The survey covered 120 units operated by utilities interested in heat rate improvement programs. It showed that heat rates at those stations were, on average, 1000 Btu/kWh higher than the design level. The range was 100 to 3250 Btu/kWh.

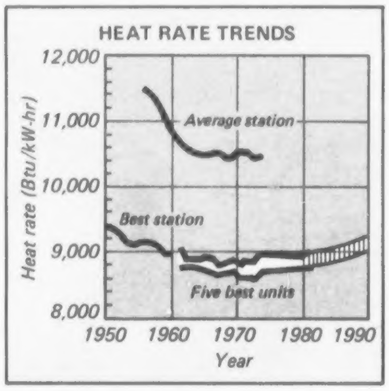


Fig. 2. The historical improvement in power plant heat rates stopped in the early 1960s.

The survey also determined how much of that loss was recoverable, in the opinion of the respondees. The range of results is shown in Figure 1. The mean saving is 419 Btu/kWh.

Estimates of where the improvements could come from were also turned up. For example:

- A one-inch (Mercury) improvement in turbine backpressure was judged to be worth 200 Btu/kWh.
- A 10F drop in flue gas temperature is good for 36 Btu/kWh.
- A one percent cut in excess oxygen is worth 30 Btu/kWh.

Another area targeted for EPRI research programs is on-line performance monitoring. Investigation of efficient stations—Duke's Marshall and Belews Creek plants, TVA's Bull Valley station, and AEP's Amos plant—shows that continuous monitoring of component performance is important to success.

EPRI feels that on-line performance monitoring technology needs to be improved and that instrumentation is a particular problem. A project is being developed to demonstrate the state of the art in monitoring at Potomac Electric Power Co.'s 575-MW Morgantown unit 2. Subcontractors included Power Technologies Inc., Lehigh University, and Combustion Engineering, Inc. The demonstration is expected to be completed in late 1985.

EPRI is also interested in improving the efficiency of new plants. Armor recounted how the historical improvement of power plant efficiency stopped in the early 1960s, as shown in Figure 2.

"I hesitate to say there's little new," Armor told the conference, "but the industry stopped producing innovations for the last 20 years." He cited the end of orders for supercritical-pressure units as an example.

EPRI feels, as a result of a two-year study by two design teams, that an "advanced" plant could be a whopping 10 percent more efficient than the best now being offered.

An essential part of that design would be supercritical pressure, according to Armor. He pointed out that every new fossil plant being built in Japan has a supercritical cycle. They're going in now with steam conditions of 4500 psig/1050F/1050F/1050F. By the year 2000 Japanese utilities will move to 5000 psig/1050F/1100F/1100F.

By then, Armor added, the Japanese intend to be the leaders in power plant design. With dim U.S. market prospects discouraging research by U.S. hardware suppliers, EPRI hopes to fill the gap.

Typical steam conditions for contemporary U.S. plants are 2600 psig/1005F, although there are a few new ones at 3850 psig. Armor feels the next generation of U.S. plants should have double reheat supercritical cycles, as in Japan, with sliding pressure capability. Specs from the two design teams are shown in Table 2.

Armor noted that many double reheat supercritical units were installed in the U.S. in the 1960s, but none have been ordered since then. "Why did we take a backward step?" he asked.

The EPRI official doesn't feel that supercritical-pressure units deserve the bad availability rap they've gotten. He claimed that initial problems have been overcome and that the supercritical units now in operation in the U.S. have average availability equal to that of the average subcritical unit. The latest generation of supercritical types, he added, are far superior in availability to the latest generation of subcritical units.

Armor claims the EPRI studies are turning around the thinking of U.S. utilities, who showed no interest in supercritical pressure a few years ago. He notes that half the units now on the drawing boards will have supercritical pressure cycles.

The EPRI studies show that the added capital cost to achieve 10 percent higher efficiency is justified by fuel cost savings for baseload (4000 hours) plants. Lifetime savings as high as $159 million were estimated. Armor noted that Japan's higher fuel costs make more efficient cycles easier to justify.

TABLE 1
TOP 20 GENERATING UNITS—BY HEAT RATE

	Unit	Capacity	Utility	Unit heat rate
1.	Marshall 3	630 MW	Duke Power	8901
2.	Marshall 4	630	Duke Power	8910
3.	Belews Creek 2	1120	Duke Power	8930
4.	Belews Creek 1	1120	Duke Power	8966
5.	Marshall 1	320	Duke Power	8991
6.	Marshall 2	320	Duke Power	9032
7.	Gorgas 10	693	Southern Company	9039
8.	Trenton Channel 9	500	Detroit Edison	9066
9.	Bay Shore 4	215	Toledo Edison	9127
10.	Canal 1	566	Commonwealth Energy	9180
11.	Morgantown 2	582	Potomac Electric Power	9296
12.	John Amos 2	800	American Electric Power	9305
13.	Mercer 2	306	Public Service Electric & Gas	9318
14.	Brayton Pt. 3	643	New England Electric System	9320
15.	Montour 2	760	Pennsylvania Power & Light	9351
16.	Bay Shore 1	136	Toledo Edison	9362
17.	Bay Shore 3	142	Toledo Edison	9375
18.	Big Sandy 1	260	American Electric Power	9379
19.	Fort Myers 2	367	Florida Power & Light	9391
20.	Monroe 1	750	Detroit Edison	9392

TABLE 2
ADVANCED PLANT GENERAL SPECIFICATIONS

	General Electric, B&W Team	Westinghouse, C-E Team
Gross rating, MW	725	824
Auxiliary power, MW	51	51
Net rating, MW	674	773
Auxiliary power, % of gross	7.0	6.2
Turbine heat rate, Btu/kWh	7300	7180
Net heat rate, Btu/kWh	8875	8330
Net thermal efficiency, %	38.5	41
Throttle pressure, psig (MPa)	4500 (31)	4500 (31)
Throttle temperature, °F (°C)	1050 (566)	1100 (593)
Throttle flow, Mlb/hr	4.4	5.1
1st reheat temperature, °F (°C)	1075 (579)	1050 (566)
2nd reheat temperature, °F (°C)	1100 (593)	1050 (566)
Final feedwater temperature, °F (°C)	580	604
Number feedwater heaters (incl, deaerator)	8	9
Condenser backpressure, in. Hg.	1.5	2.5
Turbine last stage length, in. (cm)	33.5 (85)	31 (79)
Generator efficiency, %	98.7	99.1
Boiler thermal efficiency, %	89.6	89.3
Excess combustion air, %	17	15
Air preheater exit gas temp., °F (°C)	300 (149)	270 (132)
FGD inlet gas temperature, °F (°C)	235 (113)	220 (104)
FGD exit gas temperature, °F (°C)	120 (49)	120 (49)
Stack gas temperature, °F (°C)	170 (76)	170 (76)

NOTE

ONLY THE FOLLOWING PAGES OF THIS

PUBLICATION HAVE BEEN FILMED

Cov. 1, 2-3.

4/5/84
C8650-4A

Volume 62, Number 4
April 1984

09435 1984301 W 2 2044
SUITE 800 COPY # 1
STATISTICAL REFERENCE IND
CONGRESSIONAL INFO SVC D
4520 EAST-WEST HWY STE 800
BETHESDA MD 20814

Electric Light & Power

THE NEWS MAGAZINE OF ELECTRIC UTILITY MANAGEMENT AND TECHNOLOGY

Regulatory advocacy hit in NARUC probe of EEI funds

Dan Utroska
Associate Editor

WASHINGTON, D.C.—The Edison Electric Institute has revised upwards its figures on the amount it spends on legislative lobbying.

In response to an on-going probe by the National Association of Regulatory Utility Commissioners, EEI now says it actually spends 20 percent of institute expenses on such activities, rather than the 14 percent it had earlier estimated and reported to NARUC.

In addition, EEI states it spends 15 percent on regulatory activities. According to NARUC, this brings to 35 percent of institute expenses activities that are related to legislative lobbying and advocacy support and thus stand potentially to be disallowed from being passed along to ratepayers.

The association of regulators has decided to look into EEI expenditure in its effort to provide some generic guidance to state commissions when these are faced with the issue of determining how much of utility contributions to EEI are legitimately collectible from ratepayers.

In a preliminary report issued late last year, NARUC, lamenting that it was not getting full cooperation from EEI in gathering needed data, said it was forced to make "judgment" allocations on how much of EEI dues should be charged to ratepayers and how much to shareholders (see *EL&P*, February 1984, page 1).

"It is our judgment that one-quarter to one-third of EEI dues payments by member utilities should be borne by the shareholders," NARUC said in its preliminary report. This figure was immediately contested by EEI; the institute's Douglas Bauer called it "a number in the air" and "an arbitrary judgment."

Now EEI has issued its actual 1983 "disaggregations" showing that 2 percent of its expenses go for strict lobbying, 18 percent for broad support of legislative activities, and 15 percent for regulatory activities. These figures, which total 35 percent, are seen by NARUC as confirmation that its estimate of up to 33 percent as potentially disallowable were right on target.

Understandably, EEI not only contends that the 20 percent of EEI dues should be allowed expensed, but argues that even if this is not recommended, regulatory functions are a different activity entirely and therefore certainly not disallowable.

Addressing EEI regulatory func-

Continued on page 55

Met Ed plea bargain accepted

HARRISBURG, PA—Metropolitan Edison Co. pleaded guilty in Federal court to a criminal charge that the utility operated Three Mile Island Unit 2, over a six-month period, with an inaccurate and unreliable water inventory testing procedure.

In a plea bargain struck with U.S. Attorney David D. Queen and approved by Federal District Judge Sylvia Rambo, Met Ed agreed to pay $45,000 in fines. The utility pleaded no contest to six charges and four others were dropped.

As part of the agreement, Met Ed said it will provide $1 million for an emergency planning fund for the five county area around TMI. The company said it will not claim the sum for either tax or rate-making purposes.

Last November, Queen announced the 11-count indictment after the conclusion of a three-year grand jury investigation.

First Assistant U.S. Attorney James West said Met Ed pleaded guilty to a regulatory violation that is a criminal felony under the Atomic Energy Act.

General Public Utilities Corp., holding company for Met Ed, said it will ask the court to make public the evidence and grand jury records of the case, so the Nuclear Regulatory Commission can conclude its own investigation.

GPU Chairman and Chief Executive Officer William G. Kuhns said, "The indictment was settled because it would not serve the purpose of either the company or the government to go through the costly and lengthy process of a trial and possible appeals."

"Put very simple," admitted Kuhns, "the behavior identified by the U.S. Attorney relating to the water inventory tests (leak rate tests) was totally unacceptable. There can be no question about that."

In a 20-page statement of fact submitted to the court by the U.S. attorney, the government said that virtually "every record" concerning the

Continued on page 8

'We prevented a blackout': WSCC

Load shedding totals 7700 MW in six states

A 500-kV line outage caused by malfunctioning protective relays led to widespread load shedding in six western states affecting nearly three million customers for periods as long as two hours.

The outage took place late in the afternoon on February 29 on the AC Pacific Northwest-Southwest Intertie and led to a total of nearly 7700 MW of load being automatically shed.

"This was not a blackout," said Robert Dintelman, assistant administrative manager of the 14-state Western Systems Coordinating Council (WSCC), referring to newspaper and television reports that called the out ages a blackout of the western U.S.

"We prevented a blackout by selected tripping of load," Dintelman added.

He explained that two sets of apparent equipment malfunctions led to the widespread load shedding program. The first was the failure on the AC Pacific Northwest Intertie, two 500-kV AC lines that pass from southern Oregon through Pacific Gas & Electric's system. The second was the failure of the WSCC system to automatically separate into northern and southern islands following the intertie outage as it was designed to do.

The 500 kV link opened late in the afternoon on February 28. The lines were fully loaded, carrying nearly 2800 MW from the Pacific Northwest to California utilities. A Pacific Gas & Electric spokesman said the failure had been traced to misoperation of protective relays as of early March.

WSCC's Dintelman said that, following the failure of the WSCC separation system to operate as designed, several transmission lines in states outside of California tripped out. The WSCC then separated into three islands: a capacity-deficient California-Southern Nevada region; a now ca-

Continued on page 2

FFTF to become working power reactor?

For about $150-million, plus some $42-million worth of materials and parts from the abandoned Clinch River Breeder Reactor, DOE's Fast Flux Test Facility, shown here, could be converted to a working power reactor capable of meeting all the electrical needs of the Hanford Engineering Development Laboratories. According to Westinghouse Electric Corp., operator of the DOE facility, a conceptual design report in support of project authorization was submitted at DOE's request last Fall in hopes of gaining authorization in the 1985 fiscal budget. The conversion would add steam generators to two of three existing secondary sodium cooling loops to drive a single turbine-generator.The power generated, 108 MWe (gross), would be fed to the Bonneville Power Administration grid. An article describing the achievements of the FFTF is scheduled to appear in May EL&P.

Behnke named Man of Year

BARRINGTON, IL—Commonwealth Edison Company Vice Chairman Wallace B. Behnke has been named Electric Industry Man of the Year for 1984.

Readers of *EL&P* voted Behnke the honor. Robert A. Lincicome, *EL&P* editor, said in announcing the award that Behnke was honored for his "personal leadership in the electric utility industry's battle to retain the nuclear power alternative and for his contribution to Commonwealth Edison's nuclear power construction program."

The award will be presented to Behnke at the All Engineers Dinner at the American Power Conference in Chicago April 25. The presentation, which will be made by Lincicome, carries with it a $1,000 contribution in Behnke's name to the university of his choice.

Behnke is the ninth man to receive the *EL&P* award. Last year's recipient was William Gould, chairman and chief executive officer of Southern California Edison Company.

A feature on Behnke begins on p11.

Foreign Power Briefs

- **China** has tentatively agreed to store large quantities of radioactive waste from European nuclear reactors in exchange for Western currency, reports *The Washington Post*. According to the *Post's* sources in China, the country will earn up to $6-billion over the next 16 years for storing radioactive wastes in the remote Gobi Desert. The newspaper said a letter of intent containing basics of the plan was signed in January between three West German firms active in the nuclear supply business and China Nuclear Energy Industry Corp., a state-run enterprise. The West German firms lined up dozens of contracts from nuclear facilities in western Europe. *The Post* said China agreed to receive 4,000 tons of spent nuclear fuel.

- **Pakistan's** national rural electrification program will be getting the assistance of 130 American Electric Power System (AEP) employees over the next five years. A joint venture made up of AEP Energy Services, Ebasco Overseas Corp., and International Training and Education Company received an $18-million contract to provide management and technical consulting services to Pakistan's Water and Power Development Authority, said AEP. The utility's employees will work in Pakistan for at least two years. They will be involved in management, finance, commercial operations and line-mechanic training. Other AEP employees will be in Pakistan for assignments ranging from one to 10 months.

- **The Canadian Electrical Association (CEA)** reports that national electricity consumption has been on a steady rise since June 1983. By November of last year, consumption was up 7.6 percent over the same period in 1982. CEA says that despite the upturn, Canada still has large energy surpluses. Seven new generating units went on-line in 1983 with a combined capacity of 2521 MW. According to CEA, half of the additions were nuclear plants. Nuclear power now comprises 8.4 percent of the total Canadian generating capacity.

- **A Swiss-designed magnetic coil**, shaped like a 44-ton doughnut, may hold the key for turning sea water into energy. Brown Boveri Corp., (BBC) said the 20 ft high magnetic coil will create a magnetic field 250,000 times stronger than the earth's magnetic field. BBC, manufacturer of the coil, said that if the technology succeeds, a large city can be supplied with electricity for months on just a few pounds of hydrogen. Scientists say the key to the technology is creating magnetic fields that can confine and heat hydrogen fuel to a temperature of 100 million degrees C.—about six times as hot as the sun's surface.

- **The Queensland Electricity Generating Board of Australia** said it has placed an order worth approximately $1 million with Westinghouse Electric Australasia Limited for a data acquisition system for the Swanbank B power station near Ipswich. The Westinghouse system will monitor the performance of Swanbank B's four 125,000-kW coal-burning units and supply the operators with the information they need to run the station and analyze the performance of the equipment.

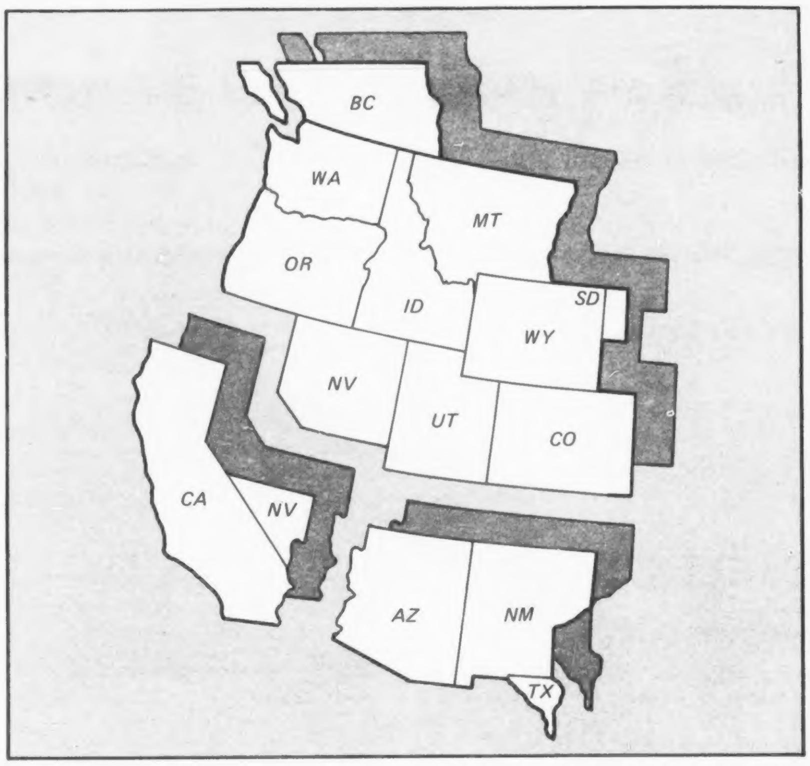
- **Compagnia Elettrotecnica Italiana S.p.A.** (CEI), said it has received a $3-million contract from the Arab Sudanese Starch and Glucose Company to build a diesel power plant near Khartoum, Sudan. CEI is a wholly-owned company of the Dravo Corp. affiliate, Dravotec, S.p.A. of Milan. CEI said it will supply engineering, delivery, erection and technical assistance for the three, 1,500 MW diesel generators. The plant is scheduled to be completed in January 1985.

In This Issue

Editorial 4
Calendar 9
Wallace B. Behnke, vice chairman of Commonwealth Edison Company, has been selected 1983's Electric Industry Man of the Year by the readers of *EL&P*. 11
Load management received a lot of attention at the IEEE winter power meeting in Dallas.T/D23 ....
Exotic energy sources don't look too promising in the near future in the opinion of many utility managers.G 31
New Products 49
New Literature 53
Personnel 60
Readers' Service 61
Regulatory Review 66
Management Methods 68

EL&P readers whose responsibilities include both Generation and Transmission/Distribution receive both technology sections. Other readers receive the technology section that applies to their respective area of responsibility. The Generation edition is indicated by a single dot (•) in the upper right corner of page 1; the T/D edition carries two dots (••). All readers receive EL&P's industry news section.

Load shedding . . . from page 1



Following the PG&E T-line outage, the WSCC separated into three islands and 7700 MW of load was shed in six states.

pacity-rich Arizona-New Mexico-El Paso island; and a third island containing the rest of the western states that was largely unaffected.

After the Arizona-New Mexico region separated, an over-frequency problem resulted from the generation surplus in that island causing several power plants to trip out.

The widespread load shedding took place automatically in response to the under-frequency resulting from the loss of generation. Relays operated to drop a total of 7716 MW of load in six states to balance generation with demand while generation was restored.

The largest amount of load was dropped by PG&E which cut off 2450 MW to about 1 million customers. At the time of the T-line outage PG&E demand was 10,500 MW. The intertie outage cost PG&E 1500 MW and the resulting separation from Arizona cut off 2000 MW more for PG&E and other California utilities.

PG&E reported that it brought hydro plants off reserve into operation and restored service to the "vast majority" of customers within 12 minutes. It took two hours to fully restore service.

The AC line that failed was reclosed and operating by 7 PM, slightly more than one hour after it went out of service. The line has been functioning normally since the outage but not at full load.

According to WSCC's Dintelman, other western utilities affected by load shedding included:

- Los Angeles Dept. of Water and Power—345,000 customers, 625 MW, service restored within one-half hour,
- Southern California Edison—750,000 customers, 2000 MW, back up within 18 minutes,
- San Diego Gas & Electric—149,000 customers, 250 MW, service back in two hours,
- Sacramento Municipal Utility District—60,000 customers, 120 MW, back in 10 to 20 minutes,
- Nevada Power—86,000 customers, 300 MW, back in one hour and 19 minutes,
- Arizona Public Service and Salt River Project in Phoenix—300,000 customers total, each dropped 600 MW for one hour,
- Sierra Pacific Power—50,000 customers, 200 MW for one hour,
- El Paso Electric—30,000 customers, 130 MW, back within one hour,
- Public Service of New Mexico—20,000 customers, 100 MW for 30 minutes.

Dintelman speculated that if the WSCC had separated as it was supposed to, there would have been less load shedding required.

Similar situation

He recalled that a line outage in December, 1982 caused by severe storm damage to transmission towers led to a similar situation. The line that went out was the same AC intertie, but the outage occurred south of San Francisco. There was even more load shed in California, Arizona, and Nevada in that occurrence, Dintelman said.

The official said a task force was being formed by WSCC to investigate the situation and recommend steps to correct any problems found.

PSI dismisses 80

PLAINFIELD, IN—Public Service Indiana (PSI) said it will dismiss 80 employees in the generation and transmission area.

The utility said the cuts will involve engineers, supervisors, training personnel, office workers and beginning bargaining unit employees at Public Service's generating stations.

PSI's Senior Vice President W.E. George said, "Unfortunately, it's necessary in the fossil power department to keep only those people with skills that are absolutely necessary to generate and transmit electricity. Therefore, we're making cuts in training and staff support services which are needed, but unfortunately we must do without because of our present cash-flow situation."

Since June 1982, the utility has reduced its non-nuclear work force by nearly 16 percent. In addition, said the utility, more than 1,100 PSI employees lost their jobs when construction was halted at the Marble Hill nuclear plant in January.

Revenues, earnings up

Electric utilities fare well in '83; weather plays big role

1984 YEAR-END UTILITY FINANCIAL RESULTS
Thousands

Utility	Revenues 1983		1983 EPS	
Arizona Public Service	$1,074,009	+1.0	$3.46	+4.8
Baltimore Gas & Electric	1,638,605	+4.8	4.95	+21.6
Black Hills Power & Light	62,601	+5.6	3.20	+18.1
Carolina Power & Light	1,647,183	+7.1	3.21	+1.3
Central Hudson	473,738	+6.3	3.94	+1.0
Central Illinois	733,042	+24.9	2.33	+28.7
Central Louisiana	304,282	+8.5	2.85	+15.4
Cleveland Electric Illuminating	1,210,316	+9.2	3.28	+9.0
Commonwealth Edison	4,570,072	+10.6	4.41	+16.4
Commonwealth Energy	619,655	+2.1	4.63	+89.0
Consolidated Edison	5,515,604	+8.8	4.16	+17.2
Dominion Resources	2,611,720	+10.6	3.28	+10.4
Eastern Utilities Associates	302,450	+4.9	2.80	+24.4
Empire District	116,079	+10.2	2.51	+19.0
Florida Progress	1,338,139	+10.3	2.64	+20.0
General Public Utilities	2,480,304	+3.1	.84	+37.7
Hawaiian Electric	622,578	-9.4	4.12	+.5
Indianapolis Power & Light	427,542	+7.5	4.17	+22.3
Iowa Public Service	388,090	+4.5	3.31	+47.1
Iowa Resources	457,916	+18.7	4.46	+21.9
Kansas Power & Light	859,572	+78.5	4.66	+29.4
Minnesota Power	374,068	+2.7	3.82	+8.8
Montana-Dakota	325,112	-8.4	3.90	-4.2
Montana Power	352,435	-3.0	4.22	+8.5
Northern States Power	1,695,800	+8.6	5.60	+16.9
Ohio Edison	1,515,852	+6.0	2.22	+4.2
Oklahoma Gas & Electric	972,281	+7.1	2.68	+4.3
Pennsylvania Power & Light	1,248,397	+2.4	3.06	-8.7
Potomac Electric	1,169,729	+6.8	2.66	+16.7
Public Service Indiana	873,900	+8.0	4.46	-2.0
Public Service New Hampshire	463,484	+9.5	3.49	+27.8
Public Service New Mexico	397,474	-6.8	3.53	+9.6
Puget Power	518,511	+10.9	1.93	-10.6
Savannah Electric	142,495	+4.6	2.66	+90.0
Southern Company	5,418,043	+10.0	2.70	+13.4
Southern Indiana Gas & Electric	276,727	+22.7	4.28	+25.1
Texas Utilities	849,543	+17.8	3.90	+1.3
Utah Power	863,288	+9.3	2.31	-5.7
The Washington Water Power Co.	338,812	-.02	3.02	-4.7
Wisconsin Power & Light	555,502	+8.4	3.97	+13.1
TOTALS	**45,804,950**	**+8.4**	**137.62**	**+13.9**

Don Minner
Assistant Editor

BARRINGTON, IL—It was a banner year for most of the nation's investor-owned electric utilities.

An *EL&P* survey of 40 electric utility year-end financial statements shows that 1983 operating revenues were up 8.4 percent, while earnings per share rocketed 13.9 percent over 1982's figures.

In comparison, operating revenues of *EL&P's* Annual Top 100 electric utilities were up 9.5% in 1982, 20.3% in 1981 and 15.9% in 1980. Earnings per share rose 6.4% in 1982, 11.9% in 1981 and .4% in 1980.

Last summer's unusually hot weather and an early, harsh winter were the principal reasons for the revenue increase. A large majority of the randomly selected utilities reported that weather was the major factor in raising operating revenues.

Economy growing

A continued nationwide economic recovery also contributed heavily to the strong performance in 1983 by the country's electric utilities.

The Commerce Department reported that the economy grew at a 4.9 percent annual rate in the fourth quarter, compared to 7.6 percent in the third quarter. The nation's output before adjustment for inflation, in the fourth quarter, was $3.437 trillion, up from $3.362 trillion in the third quarter of 1983.

Consolidated Edison said operating revenues for 1983 were up 8.8 percent over 1982, while earnings per share increased 17.2 percent. Arthur Hauspurg, chairman of the board, said, "The increase in earnings was due in large part to the extremely hot summer. The summer of '83 was the second hottest since ConEd became a summer peaking company some 25 years ago."

Weather also contributed to the brighter financial picture for Wisconsin Power & Light, Montana Power, Iowa Resources and Northern States Power.

Many utilities said they are continuing the cost control measures instituted during the recession. Central Louisiana Electric Chairman and President James Henderson said that he is optimistic about the future. "However," he added, "we will maintain a hard line on expenses and take advantage of every opportunity to increase efficiency."

Effective cost controls

Minnesota Power Chairman and CEO Jack Rowe said his company's modest advances in 1983 were accomplished "through increased electric revenues and non-utility investment income, lower interest charges and effective cost controls." Rowe said Minnesota Power has not sought a rate increase in three years and has no plans to do so in 1984.

Baltimore Gas & Electric also said it is keeping its cost control measures in place, although the utility said economic conditions are improving in its service area.

Business and industry are slowly picking up activity in the battered Northeast. Pennsylvania Power & Light said industrial sales were up 4.1 percent in 1983 and commercial sales rose 2.9 percent. Central Hudson reported that industrial sales jumped 7 percent, due in large part to renewed activity with the region's cement companies.

Ohio Edison said it saw a "steady improvement in the local economy, particularly in the automotive and steel groups." The utility said that sales of electricity to other utilities resulted in $76.2 million of Edison's total revenue in 1983.

While most utilities fared well during the year, others with nuclear plants under construction saw earnings drop. Public Service of Indiana, which abandoned its Marble Hill plant in January, saw its earnings per share drop 2.0 percent to $4.46 in 1983. PSI said in January that it was going to cut its dividend by 65 percent. The utility said the "substantial decline in earnings for 1983" was due to the discontinuation of allowance for funds used during construction (AFUDC) for Marble Hill.

EL&P TOP 100 SURVEY (1978–1982)

	Operating revenues		Earnings per share	
1982	123.4 billion	+9.5	3.00	+6.4
1981	112.7 billion	+20.3	2.82	+11.9
1980	93.6 billion	+15.9	2.52	+.4
1979	80.8 billion	+13.5	2.51	+.4
1978	71.2 billion		2.50	

Arizona Public Service, the lead utility in construction of the three unit Palo Verde nuclear plant, said 85 percent of its earnings figure in 1983 was due to AFUDC, compared to 72 percent last year.

PP&L earnings drop

The owner of the nearly complete Susquehanna-2 nuclear unit, Pennsylvania Power & Light, said its 8.7 percent dip in earnings per share was due to a number of factors. PP&L Executive Vice President Robert Fortune said, "Higher costs, a regulatory decision that does not allow us to earn a return on part of our investment in generating facilities, the lingering effects of the recession during early 1983 and an increase in the number of common shares outstanding were factors in the decline."

Montana-Dakota Utilities said its earnings per share drop in 1983 was due to the sale of more common shares of stock.

The Southern Company, Commonwealth Energy, Hawaiian Electric Industries and Carolina Power & Light all reported healthy increases.

Dominion Resources, holding company for Virginia Electric and Power Company, said 1983 brought record earnings to the company. Contributing to the earnings rise was the sale of a portion of the North Anna nuclear Units 1 and 2 to the Old Dominion Electric Cooperative.

Outside the utility industry, profits were much higher in the fourth quarter than in 1982. A *Wall Street Journal* survey of 529 major corporations in February found that after-tax earnings rose 64 percent in the fourth quarter. A *Journal* survey of 115 Canadian companies found fourth quarter earnings skyrocket 118 percent from a year earlier.

JCP&L agrees to PP&L power buy

PARSIPPANY, NJ—General Public Utilities announced that a long-term power purchase agreement has been reached with Pennsylvania Power & Light for its New Jersey susbsidiary.

Beginning in June, Jersey Central Power & Light Company will buy 945 MW of power through 1995, with the amount declining uniformly each year through 1999. PP&L will be selling 12.6 percent of its electrical output. The power will be priced at cost of service.

GPU said the fuel mix of the purchase will be approximately 25 percent from nuclear, 65 percent from coal and the remainder from oil and other sources.

Herman Dieckamp, GPU president, said the purchase will supply approximately 30 percent of Jersey Central's energy requirements. "Over the long term," said Dieckamp, "the agreement is expected to produce substantial cost savings for Jersey Central customers because over the life of the contract, the cost of the purchase is expected to be well below that of alternative sources, including new capacity."

GPU strategy

Dieckamp said the agreement reflects GPU's strategy of buying power, so that construction of new generating capacity can be deferred.

C8650-

Volume 62, Number 5
May 1984

09535 1984301 W 3 75
SUITE 800 COPY # 1
STATISTICAL REFERENCE IND
CONGRESSIONAL INFO SVC D
4520 EAST-WEST HWY STE 800
BETHESDA MD 20814

Electric Light & Power

THE NEWS MAGAZINE OF ELECTRIC UTILITY MANAGEMENT AND TECHNOLOGY

Veil of uncertainty lifted at HL&P's South Texas project

Don Minner
Assistant Editor

WASHINGTON, D.C.—Houston Lighting & Power's (HL&P) South Texas nuclear project has received a preliminary stamp of approval from the Nuclear Regulatory Commission's Atomic Safety and Licensing Board (ASLB).

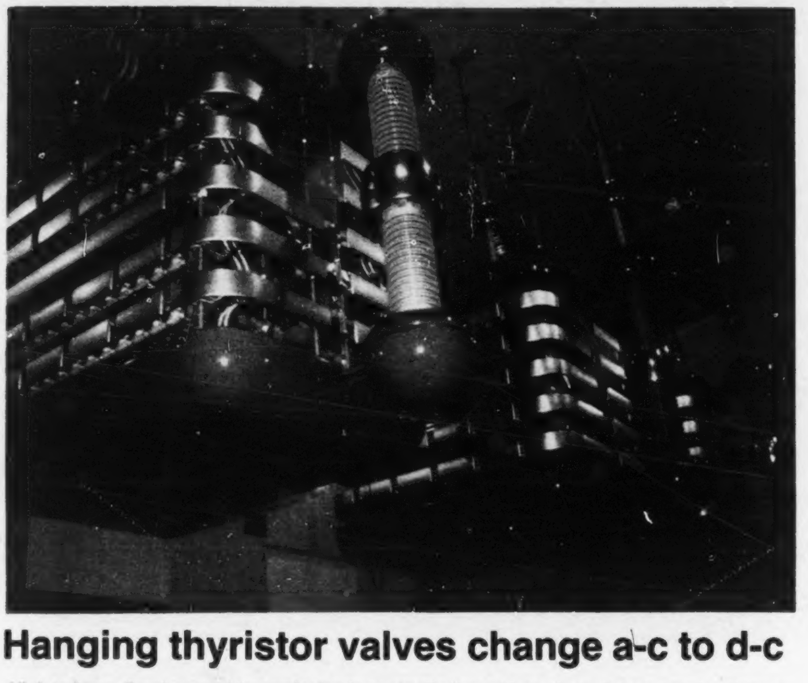
In its March report, the board said, "We perceive this project as one which, although in trouble at an earlier date, has now likely 'turned the corner'."

HL&P's Manager of Nuclear Information Don Beeth said that the ASLB report "has lifted a cloud that has hung over the project for the last several years."

Beeth said the South Texas Project (STP) is now "a shining light in the nuclear industry."

In 1980, the NRC's Office of Inspection and Enforcement released a report citing 22 non-compliances in HL&P's construction practices at the project site. The NRC also said that substantial deficiencies existed in the utility's quality assurance and quality control (QA/QC) programs. HL&P was hit with a $100,000 fine and an or-

Continued on page 2



Hanging thyristor valves change a-c to d-c

High voltage direct current transmission is presently the subject of new interest and activity, as utilities contemplate or construct new projects or recondition older ones. Here, three twin valves hang from the ceiling of one d-c converter facility of the Pacific Intertie upgrade being built by ASEA. A second, adjacent building houses three additional twin valves, raising the capacity of the intertie from 1,600 to 2,000 MW. Valve parameters are 2,000 amperes at 100 kiloVolts. An array of series-connected thyristors are inside each of the three valve housings. The new design hangs the valves from the ceiling in order to more fully insulate against seismic shock. Now in the final stages of installation, valve commissioning is expected in early 1985. A Special Report, which includes a look at why HVDC is again becoming popular, begins on page 35.

Policy issues raised in EPA rule proposal on particulates

WASHINGTON, D.C.—Fundamental issues concerning how the Environmental Protection Agency sets air and water quality standards are being raised as part of the agency's recent move to promulgate new regulations for particulate matter.

Particulate matter is the general term for the substances consisting largely of dust, dirt and smoke.

EPA has proposed major revisions in the national clean air standards for particulate matter, changing the focus from larger total particles to smaller, inhalable particles that are more damaging to human health.

But the agency argues that although available evidence clearly supports continuing the regulation of particulate matter, selecting a specific quantitative standard that provides an adequate margin of safety involves uncertainties so large that the entire regulation-setting process may have to be revised in order to accommodate them.

"There are several aspects of this [regulatory-making] process that are especially troubling to me," EPA Administrator William D. Ruckelshaus said at a press briefing the day the agency announced its plan to change

Continued on page 3

N.J. commission blasts EPRI foreign research award

PSE&G is required to escrow entire cost of contract

Dan Utroska
Associate Editor

NEWARK, N.J.—Outraged that the Electric Power Research Institute had awarded a $5.7 million research contract to a foreign firm at the expense of New Jersey and other American companies, the state's Board of Public Utilities (BPU) has disallowed the full cost of the contract in annual expenses by Public Service Electric & Gas Company. There were indications at press time, however, that the BPU might relax its stance.

Specifically, the board prohibited company use of money collected from ratepayers for PSE&G membership in EPRI up to the full $5.7 million value of the research contract.

The board said its ruling was based on its finding that the research contract to Sulzer Brothers, the Swiss pump manufacturer, had not been awarded fairly and would undermine the sales position of U.S. manufacturers.

Contract for development

The contract was for the development of an improved design for boiler feed pumps for large coal-fired and oil-fired electricity plants.

An EPRI spokesman, in a telephone interview with *EL&P*, refuted the charges levelled by the New Jersey board.

In its March 16 decision, the board said it would allow Public Service to collect its full annual EPRI membership payment of $6.3 million from ratepayers, but $5.7 million of this—the full cost of the Sulzer contract—would have to be held in escrow for possible use in funding a pump research project proposed by American pump manufacturers.

The board's ruling places Public Service in an untenable position. The utility, a long-time supporter of EPRI, now either has to fund the research of American pump manufacturers and drop out of EPRI, or alternatively, fund both research efforts and collect only once from ratepayers.

No double payment

"We will not continue to pay EPRI and fund this payment of $5.7 million, that is clear," said PSE&G attorney Frank Delany.

At press time in mid-April there did appear to be some room for maneuvering, however, and even the possibility of a negotiated settlement, as the board had not yet issued a formal order on the matter as it had promised to do nearly a month earlier.

In addition, John Ruiz, a confidential aide to New Jersey board commissioner Edward H. Hynes, said that an internally-generated motion to reconsider the ruling was presently before the board.

"The board is confident that EPRI is responding to its concerns," Ruiz told *EL&P*. "What I fully expect to happen...is that the board will treat EPRI contributions as it has always treated them: as expenses that can be recovered in rates charged to customers."

The EPRI spokesman confirmed that he believed the issue would be settled harmoniously.

Agency action is unprecedented

Yet this optimistic and amicable characterization of how the dispute might ultimately be resolved, contrasted strikingly with the more acrimonious language used by the New Jersey board in announcing its disallowance actions.

The board said then that "EPRI relied too extensively on the subjective judgments of its staff, in decisions on research contracts, limiting the ability of the EPRI board to assure fairness to all bidders in contract awards...."

The New Jersey Board of Public Utilities further charged that the Swiss contract would give Sulzer Brothers an "unwarranted advantage" in future sales in the U.S. market for this type of pump.

According to BPU commissioner Hynes, a subsequent agency investigation reportedly revealed that an EPRI manager visited the Swiss company while contract bids were being evaluated, without similar visits to other bidders, thereby appearing to favor Sulzer Brothers.

EPRI refutes BPU allegations

Regarding the charge that EPRI was too subjective in decisions regarding the awarding of research contracts, institute spokesman David Saxe said a host of review processes were in place at EPRI and that they function well to critique proposed contracts.

"We think our process for evaluating proposals in the research and development field is just about as sophisticated as you can get," Saxe said.

Acknowledging that there was no way to totally eliminate subjective judgments in reviewing contract proposals, Saxe reported that a number of outside consultants as well as EPRI's own industry advisory group reviewed the Sulzer proposal before making the award.

Staffed by numerous outside industry experts that have no direct tie with the institute, EPRI's advisory group has been put together as one independent check of proposed research contracts. At least four subcommittees under this advisory group reviewed the Sulzer contract before it was awarded, Saxe said.

Ultimately, the outside consultants, reviewers of the advisory

Continued on page 3

Foreign Power Briefs

- **A Swedish research study**, currently in progress, says a system of differential electricity pricing that allows prices to be varied from moment to moment in line with changing generating costs would result in enormous savings of imported oil for most developed countries. At the same time, pointed out the study's authors, the system could reduce costs for both producers and consumers of electricity. The study is being carried out at Linköping University in Sweden and the results are being assessed by the state-owned research and development company.

- **Turkey's electric utility** has a new 400-kV power line spanning the Bosphorous River. Siemens AG built the line for Turkiye Elektrik Kurumu in just 15 months. The line links customers around Istanbul with hydroelectric and lignite-fired plants in central and eastern Turkey.

- **Hydro-Quebec** has agreed to sell 150,000-kW of power over a 10-year period to the state of Vermont. Gov. Richard Snelling said the state will begin receiving the electricity in July 1985. Snelling said the price of the power will be 3.3 cents a kilowatthour, rising to 4.0 cents by the end of the first five years. The price for the second five years will depend on the price of coal and oil. Before the deal can be completed, a substation must be built in northern Vermont. Snelling said that if Vermont's electric utilities don't pay for the construction of the substation, he will ask the state legislature to create a state power authority to build the substation.

- **The Italian National Committee** for Research and Development in Nuclear and Alternative Energies (ENEA) said it has placed an order with Westinghouse Electric Corp., for the nuclear industry's first advanced engineering simulator. It will be used to evaluate nuclear power plant design and operation. ENEA said it will install the equipment in its Rome headquarters. Initially, ENEA will use the simulator to assist in the design of the Italian pressurized water reactor. Westinghouse said the simulator allows nuclear plant engineers and executives to analyze overall plant behavior quickly, without requiring detailed knowledge of the control room operation.

- **European Community (EC)** coal imports from the United States will increase slightly in 1984 to 25.1 million tons, compared to last year's 24.6 million tons, said the EC Commission. The group said that coal shipments from third world countries also are expected to be higher in 1984. The EC Commission reports that total imports should rise from 1983's 62 million tons to 63.2 million tons this year.

- **Ontario Hydro** said it has recommended to its board of directors that all of the pressure tubes in the two-unit Pickering nuclear plant be replaced at an estimated cost of $720 million (Canadian), including fuel replacement. Inspections have shown that the metal alloy is becoming brittle, said the utility. The units will not be restarted until the retubing is completed, sometime before 1987. Pickering-2 has been shut down since one of the tubes ruptured last August. Unit-1 has been down since November for tube inspection.

- **Saudi Consolidated Electric Company** and General Electric have signed two contracts totalling $61.8 million for a gas turbine turnkey addition to an existing diesel power station in Abha. GE said the first contract includes three GE heavy-duty gas turbines, which will provide a combined output of 150 MW. The second contract, valued at $12.4 million, is for a 132-kV substation to be built at the Abha site.

In This Issue

Editorial 4

Calendar.. 9

Garbage power gains in popularity with new projects being announced and new suppliers entering the marketplace.**G**............................ 23

Carolina Power & Light is demonstrating the effectiveness of distribution automation systems.**T/D** 31

The use of high voltage direct current bulk power transfer is again receiving renewed attention by utility power system planners. A look at why this is happening and an exploration of a new, emerging problem of system harmonics is the focus of a Special Report... 35

Chemical conditioning helps Dayton Power & Light meet emission limits with a relatively small precipitator after a switch to low-sulfur coal.**G**......... 51

New Products 55

New Literature... 58

Personnel 60

Readers' Service 61

Regulatory Review 66

Management Methods 68

EL&P readers whose responsibilities include both Generation and Transmission/Distribution receive both technology sections. Other readers receive the technology section that applies to their respective area of responsibility. The Generation edition is indicated by a single dot (•) in the upper right corner of page 1; the T/D edition carries two dots (••). All readers receive EL&P's industry news section.

South Texas project . . . from page 1

der to show why construction on the project should be allowed to continue.

Two local intervenor groups had requested a hearing on the show cause order, but it was denied by the commission. Instead, the NRC agreed to hold early hearings on the QA/QC issues. Those hearings were held between May 1981 and June 1982. Then, on Sept. 24, 1981, the utility fired its architect-engineer and construction manager, Brown & Root (B&R). Bechtel Power Corporation was hired to replace B&R, while Ebasco became constructor on the project. To the welcome relief of the utility, the ASLB issued its findings on the initial hearings in March.

Two more phases of hearings still need to be held before final approval is given to the $5.5 billion twin-reactor 2,500 MW South Texas project, but HL&P's Beeth said the utility feels those will be "much less complicated" than the first ones.

Another hearing will be held to discuss a report on B&R engineering that was done at the request of the utility by Quadrex Corporation. The third hearing will address any remaining issues. Those hearings could be held as early as the fall, said the HL&P spokesman.

Project on schedule

Beeth said that approximately 6,000 craftsmen are working 20 hours a day, 7-days a week in order to have Unit-1 ready for fuel loading by 1987. "We're right on schedule to a tenth of a percent," enthused Beeth.

As of mid-April, the project was over 50 percent complete, according to the utility. Beeth said Unit-1 was 56 percent complete and Unit-2 was 31 percent finished.

Beeth singled out the work of Bechtel and Ebasco for keeping the project in such good shape. "The cooperation between them is a marvel to behold," he said. "You'd think they were all working in the same company."

In its report, the ASLB said, "...it is our opinion that HL&P is not now deficient in character and has not demonstrated character deficiencies which would warrant denial of operating licenses."

Although HL&P's competence was questionable at the time of the NRC investigation, said the board, it now appears to have substantially improved.

HL&P's problems

The board said HL&P's problems with the project "were traceable, in our opinion, not to character defects on the part of HL&P but, rather, to deficiencies in two key ingredients of competence: experience with respect to design and construction of large nuclear facilities such as STP on the part of both HL&P and B&R, and long lines of communication which resulted in HL&P's inexperienced management failing to receive the information it required to operate a successful QA/QC program."

The board went on to say, "We now have reasonable assurance that structures which are complete and work which has been performed comply with applicable regulatory requirements, and that future work activities (including implementation of the QA/QC program for construction) will be carried out satisfactorily."

"We feel the project is in good shape," assured Beeth. "We will still have violations, but they will be few, they won't recur and we will correct them with vigor."

The ASLB report also addressed several of the charges made by the intervenor groups concerning concrete and welding at the project. The board said there is "reasonable assurance" that the concrete work and the backfill at the project site are in conformity with construction permits and NRC regulations.

As to the welding, the ASLB said, "We find that HL&P is conducting a thorough reevaluation of the STP welding program. This evaluation has resulted in the discovery of significant defects in existing welds and significant improvements in the welding program to prevent recurrence of those defects."

Intervenors recognized

The ASLB recognized the intervenor groups—Citizens for Equitable Utilities, Inc., and Citizens Concerned About Nuclear Power, Inc.—for their efforts in bringing serious QA/QC questions to the attention of the commission.

Said the board, "They (the intervenors) initially raised these issues long before the NRC recognized their significance and for this they are to be commended."

There is no basis, said the ASLB, for concluding that the utility lacks managerial competence and integrity. "HL&P is presently managing, planning and implementing its program for the balance of design and construction of STP, including its QA program," said the ASLB, "in a manner which provides reasonable assurance that future design and construction work at STP will be in conformity with the construction permits, the Atomic Energy Act, as amended, and the rules and regulations of the commission."

Acid rain plan misunderstood, says EPA

WASHINGTON—The Reagan administration's recently announced policy on acid rain has been misunderstood, according to Charles Elkins, director of the non-research portion of the acid rain program at the Environmental Protection Agency.

Noting that the policy called for greater funding for research, Elkins told the recent Energy Technology Conference meeting here, "Those who think we're in favor of no control are incorrect. We're right in the middle."

Elkins said that President Reagan asked William Ruckleshaus to "focus" on acid rain when he appointed him to head EPA last year, and that's what Ruckleshaus is continuing to do. The administration's "intense" review of the state of knowledge on acid showed, according to Elkins that, "Researchers found that what we know today is less than what we thought we knew two years ago."

Elkins said that while researchers know there is acid lake damage occurring downwind from regions that emit sulfur dioxide from power plants they don't know how extensive the damage is and they don't know what effect a control program would have on the lakes. Another big question is the effect of acid deposition on forests, a big problem in Germany that has not occurred here yet. "Are we just a few years behind?" Elkins asked.

The official said that a survey of lakes and forests now being conducted will show the extent of current damage and how fast the "ecological clock" is turning.

High Voltage d-c transmission plans are re-energized; harmonics issues emerge

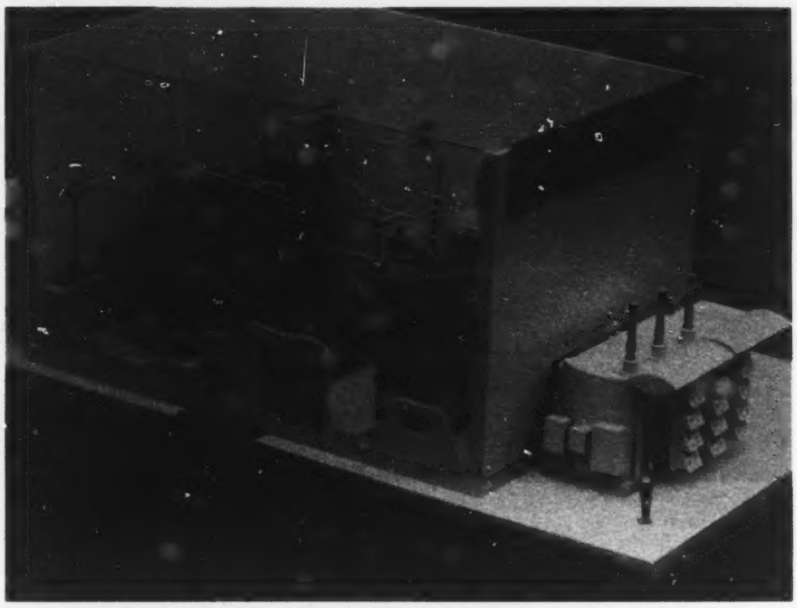
Dan Utroska
Associate Editor

Thomas Edison would be happy. The idea of direct current power networks is once again being seriously promoted by power system planners.

The venerable old researcher, who initially conceived of a vast electrical network spanning the United States, envisioned that it would be constituted of direct current components because of the inherent advantages in this type of power generation and transmission.

But Edison lost out to the alternating current advocates, principally on the basis that a-c voltages could more easily be stepped up or down for transmission and distribution.

Today, a confluence of new social, economic, and technical developments again has brought direct current transmission to the forefront of contemporary power system analyses. Principally conceived as a constant-voltage link in an a-c network, d-c offers the promise of otherwise unobtainable economical energy transfer, enhanced power control, and greater system reliability.



Artist's rendering shows the main components of a General Electric high voltage d-c converter station. Solid state thyristor valves transform a-c power to d-c, while the converter transformers provide phase shifts required for valve operation and maintain valve voltages.

The recent surge in d-c system orders is occurring against a backdrop of a more general focus of attention on electricity transport mechanisms. This focus stems to large degree from increasing financial, regulatory and demand uncertainties that make new power plants more difficult to construct. The growing disinclination of electric utilities to build new generating plants, combined with very large capacity excesses in many parts of the U.S. and in Canada, naturally has turned analytical and engineering heads toward new transmission regimes, in an effort to equalize regional power disparities.

"Basically, the industry is facing the recognition that the emphasis in power systems has shifted from generation to transmission and distribution," notes Walter Ros of General Electric Company. "The public utility commissions are doing the same thing."

Even though the most recent survey by the National Electrical Manufacturing Association shows that electric utilities again have decreased their estimates of new transmission lines to be added through 1992 (*EL&P*, April), analysts looking at high voltage direct current (HVDC) potential see measurable growth in new facilities just over the horizon.

Economical energy transfer

One source of these new T-line facilities is the possible benefits from economical energy transfer. For example, in late March Southwestern Public Service Company and Colorado-Ute Electric Association Inc., announced they had entered into a joint agreement to construct a $19 million, 125 kiloVolt HVDC line between SPS facilities near Guymon, Oklahoma and Colorado-Ute facilities at Violas, Colorado.

SPS is a summer peaking utility, while Colorado-Ute is a winter peaking generation and transmission cooperative. "Under our agreement, Colorado-Ute will generate some power for our customers during summers," said Bert Ballengee, SPS president and chief operating officer. "We'll generate some power for their customers during winters. That will hold down costs for both utilities."

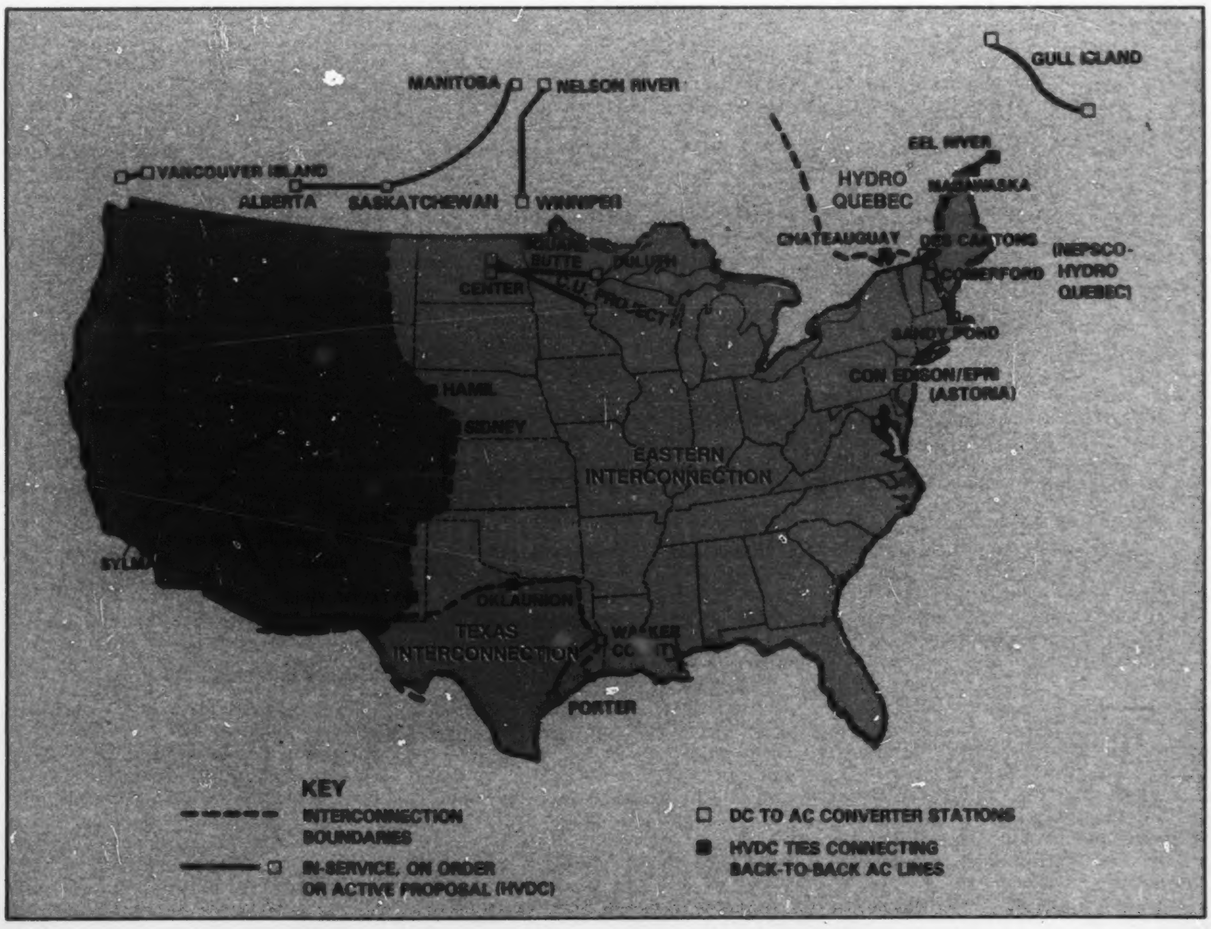
In announcing the joint agreement Ballengee said it would have been technically impossible for the two utilities to exchange power directly without the direct-current facility. This is because construction of the system provided for the possibility of energy transfer between two asynchronous systems, or systems that have different transmission characteristics. In this case the line crosses the boundary between the Western and Eastern interconnnection (see map).

According to General Electric Company's Dr. Frederick J. Ellert, there is great potential for this kind of power exchange. Electric energy, he says, could be transferred very economically from those areas of the country where surplus low-cost generation exists, to other parts where expensive oil and gas are being burned.

Ellert calculates that currently about 135 gigawatts (GW) of electric power is being fueled by oil and gas in the U.S. This is produced by plants

Continued on page 36

Project	Rating, MW
[illegible]	
*Salt River	1600-2200
Intermountain	1600
Hydro Quebec- New England Electric (Canada-United States)	690-2000
C.U. Project	1000
Walker County	520-1040
Square Butte	500
Pacific Intertie	400
Oklaunion	200
Eddy County	200
Miles City	200
*Sidney	200
*Blackwater	200
Hamil	100
Astoria	100-400
[illegible]	
Nelson River	1620-2000
*Manitoba-Saskatchewan- Alberta	1500
Chateauguay	1000
*Gull Island	800
Vancouver Island	670
Madawaska	350
Eel River	320
[illegible]	
*Japan	15,000
Brazil (Itaipu)	6000
USSR (Ekibastuz)	6000
*China	2000
England-France	2000
*Malaysia	1200
USSR-Finland	1000
*Mexico	900-1800
*Philippines	600
*India	500-1000
Austria	500
*Bulgaria-Greece	300
[illegible]	[illegible]



'When the line becomes long enough,...then there is a straightforward justification for the use of direct current.'

High voltage direct current . . . from page 35

principally located along the coast in New England, and the mid-Atlantic states, Florida, Louisiana, Texas, Oklahoma, and California. In a GE-conducted study, these plants were found to have an average annual capacity factor of about 45 percent and it was estimated that about 30 percent (or about 40 GW) of this oil and gas-fired generation could be displaced by lower cost fuels.

"The annual saving in the United States would exceed $4 billion and would pay back the cost of the additional transmission required in less than two years," Ellert said. "Due to the long distances involved, more than half of this transmission could be in the form of HVDC transmission."

But coal-fired electricity need not always displace oil and gas capacity in order to achieve economical energy transport savings. Hydro Quebec has enormous hydropower resources that are already built and to the extent that this power is excessive in Canada, its incremental cost per kilowatt-hour approaches zero. Thus, the use of HVDC to interconnect that Canadian utility with the Northeastern United States promises relatively inexpensive power to that region, even after the cost of the new T-line is calculated and amortized.

HVDC systems need not have transmission lines associated with them, but can be used exclusively to link asynchronous a-c systems. As the accompanying map shows, the U.S. is divided into three major interconnections; the Eastern interconnection, the Western interconnection, and the Texas interconnection. By installing d-c links, two nonsynchronous a-c systems can be interconnected for the purposes of power transport.

HVDC growth estimates

Overall, when reasons in addition to economical energy transfer are considered as possible stimulants for new HVDC construction, it is estimated that the potential market worldwide is about 15 to 20 GW over the next five to 10 years. As can be determined from the accompanying chart, there is currently about 12 GW of HVDC capacity now either in construction or operation in North America.

GE forecasts that HVDC systems are likely to grow at about 15 percent per year from now through 1990. ASEA, the other major supplier of HVDC systems, estimates that over the next five years, average annual HVDC system increases in the U.S. will be about 500 to 1000 MW.

Certain recent technical and economic developments associated with high voltage d-c systems do appear to offer the possibility of vigorous growth in the near and mid term. The actual construction of a number of new HVDC systems around the world give added support to this view.

But opposing these developments are concerns that worry HVDC advocates and that pose serious obstacles to the rapid growth of the technology that proponents foresee. Clearly, a tension has been set up among these forces and only the evolutionary pace of future technical advances and regulatory innovation will decide the outcome.

Perhaps the two major elements working to support the HVDC growth are the differences that now exist across the U.S. in electric generating capacity and the measurable improvements that have been made in high power d-c converters and solid state controls. The latter development offers HVDC systems of substantially enhanced reliability, as contrasted with earlier systems. Both of these tend to make HVDC systems appear attractive.

D-C converters much improved

Direct current converters are, simply, those devices that transform a-c current into d-c. Specifically, they are rectifiers that transmission engineers refer to as valves.

Today, modern thyristor valves have replaced the older mercury arc valves. Mercury arc valves have been installed and are operating in 11 of the 12 HVDC systems commissioned between 1954 and 1975 and are responsible for whatever measure of success current HVDC systems have enjoyed.

ASEA introduced the first HVDC system using thyristor valves in 1970; General Electric offered its system commercially two years later.

State-of-the-art thyristors are now larger in diameter than their predecessors and thus have increased power handling capability. Present-day thyristors have test voltages of up to 5 kV. Thus a single bridge made of six, 100-mm diameter thyristors can deliver 5 MW of continuous rated d-c power.

The increase to 100 mm diameters today from the approximately 25 mm diameters in the mid 1960s, means that currently fewer thyristors are required for a given power rating, and most engineers believe that further improvements are possible.

In addition, total losses experienced by a d-c converter station reportedly have been reduced to about one percent of the d-c power rating, with about one-third of the losses attributable to the water-cooled thyristor valves.

Further, HVDC growth advocates point to the enhanced reliability of newer, more recently designed systems. In the event of a fault on one electrical pole (plus or minus) of a d-c system, the earth can be used to carry the current of the functioning pole.

Energy availability is one measure of reliability of HVDC systems. According to General Electric, energy availability, on an annual basis, has been over 98 percent for its equipment used in HVDC systems. ASEA reports equivalent figures.

Elegant controllability

One of the more elegant features of HVDC is its preeminent controllability. With such a system, current or power can be defined and maintained in order to improve the dynamic performance of related a-c systems.

ASEA's Power Systems Center director Dr. Willis F. Long points out that d-c systems can respond to power changes extremely rapidly. For example, he notes that acceptance tests on the Pacific Intertie (see map) verified that full power reversal—from 1440 MW North-to-South to 1440 MW South-to-North—could be achieved in ⅓ of a second.

Long raised the possibility that, with the development of efficient d-c breakers, d-c networks could be set up, thereby expanding the use of HVDC beyond present day point-to-point applications.

A good example of the limitations of d-c transmission without d-c circuit breakers is the Pacific Intertie line. It has only two terminals: one at The Dalles, Oregon, and the other at Los Angeles. Had HVDC breakers been commercially available when the intertie was built, branch lines could have been extended to San Francisco, Salt Lake City, and Phoenix. But without such breakers to isolate faults on the branch lines, such "networking" becomes impractical.

High voltage direct current breakers have been difficult to develop. Unlike alternating currents, high voltage direct currents flow in one direction only. Attempts to interrupt the flow by placing a gap in the conductor merely causes the current to arc over the gap. At 500 kV, for example, even a gap of 50 ft is insufficient to stop the current flow; it will continue to stream, twisting in the process like lightning.

Recent developments, however, suggest that successful breakers are at hand. The ability to control power flow with the precision that HVDC circuit breakers would provide has wide applicability in power disturbance situations (such as the infamous New York blackouts), as well as in routine system maintenance.

Dr. Jerome Meisel of Wayne State University has looked into some possible applications. In a recent study conducted for the Department of Energy, Meisel analyzed a transmission emergency situation similar to the 1977 New York blackout.

Here, a large metropolitan area that imports nearly one-half of its power suffers a power generation emergency. Although numerous surrounding utility service areas are connected and have excess capacity to share with the troubled area, a-c electricity transport to the affected area is not directly controllable. Efforts to provide the downed area with additional generation under an a-c regime, inevitably overload incoming a-c tie lines, thereby tripping them out of service.

To solve this reliability problem, it is proposed that a single, bi-polar d-c "transmission ring" be installed circumferentially around this metropolitan area, interconnecting the rescue area tie lines at the point where each of these originates. Such a ring would have d-c converters located at the external tie-line buses. With proper controls, Meisel calculates that this ring could readily balance electricity flows on the tie-lines from any of the rescue areas surrounding the region in trouble.

Such electricity transport, he maintains, would therefore be done without tie-line overloads, as would certainly be the case if the ring were constructed using a-c transmission.

Economics still evolving

The evolution of semi-conductor technology that has introduced the thyristor converter and has correspondingly brought down the costs of HVDC has coincided with a national economy of abiding volatility. These circumstances have brought HVDC not only into direct competition with a-c facilities in many applications, but with new electricity generating facilities as well.

"When the line becomes long enough, the savings in a d-c transmission line equal or exceed the cost of the converter terminals," says GE's Jack Fink. "Then there is a straightforward justification for the use of direct current."

Presently, as a rough approximation, as the "break-even" distance for HVDC overhead transmission approaches 300 miles, it is generally considered economically prudent to considered d-c. For underground or underwater cable applications, d-c tend to be economical for lengths of about 20 to 30 miles, proponents say.

Yet, the use of d-c for asynchronous ties, installed back-to-back, is not related to conductor length and reportedly can be economically justified on the basis of the power transformation and linking services it performs. Dr. Fink notes that the average length to date of GE HVDC projects is about 45 miles.

But HVDC economics, as attractive as they may be for certain, clearly-defined instances of point-to-point facility construction, are more uncertain in other instances. The cost of the converter terminals, though reduced from former times, is still high and may preclude utilities from opting for direct current lines in many instances.

As GE's Fink notes, capital expenditures are increasingly difficult to justify in the electric utility industry. "This is an industry beset with priorities as to where to spend money," he says. And an electric company that does decide to build an HVDC line for the purposes of economical energy transfer, has to move quickly and without hindrance in order to secure the benefits it seeks. In many cases utilities with excess capacity can only be expected to offer it for a relatively short time—perhaps up to about 10 years in some cases, less in others. Sooner or later load growth will consume this excess capacity and a utility building a new T-line will have to be sure that the kilowatts eyed are still available when the line is finished.

Innovative financing needed

Compounding this demand/supply matchup, electric utilities may find it difficult to finance large, expensive transmission projects over this relatively short time period. GE's Dr. Ellert notes that under traditional ratemaking schemes, a company would have to amortize its T-line investment over decades, while ratepayers would be the immediate and continuing beneficiaries of inexpensive power importation. Such circumstances, short of other compensating considerations, could provide strong disincentives for utility investment in HVDC. Such circumstances, therefore, argue strongly for innovative ratemaking schemes.

Such schemes are not without precedent, however. The Florida Public Service Commission has, as part of its regulations, an oil back-out cost recovery clause. This rule establishes criteria under which a utility will be granted expedited capital recovery if it can demonstrate that construction of a new generation or transmission facility will pay for itself in oil savings.

In response to this rule, Florida Power & Light is building a 500-kV

Continued on next page

> 'The sophistication of the American consumer has gotten to the point where he expects more out of the power system than he expected even five years ago.'

High voltage direct current . . . from page 36

a-c transmission line that will run along the east coast of Florida and interconnect with Georgia Power Company. FP&L has "qualified" construction of one segment of the line under the PSC's new rule by demonstrating that projected oil savings associated with the line would, over a 10-year period, offset the revenue requirement needed to construct the project.

Thus qualified, costs are recoverable through the fuel adjustment clause. If, however, oil savings *more* than offset these revenue requirements, the company is entitled to retain two-thirds of the savings. According to PSC spokesman Bob Trapp, this turns out to be a form of accelerated depreciation and aids the company's cash flow situation.

This innovative regulatory scheme would apply equally to an HVDC line, should this ever be needed in the area. The only requirement is that it pay for itself in oil savings.

While Florida may not be the only state that has an innovative rate scheme to encourage economic energy supply, it surely is one of the very few.

Further, the development of multiterminal HVDC systems has been hampered in part by the present lack of experience with these systems. "Planners are not familiar with the capabilities of these systems," notes Dr. Robert Lasseter of the University of Wisconsin. "No adequate software simulation tools exist, and new concepts of operation of multi-terminal systems different in nature from the concepts used for the operation of point-to-point HVDC systems need further evaluation."

Circuit breaker 'breakthrough'

Also needing further evaluation is the recent development—termed a "major breakthrough" by engineers associated with the project—in the area of d-c breakers announced in mid-March by the Bonneville Power Authority. Without such a breaker, the development of multi-terminal HVDC networks is precluded.

BPA reported that it has completed successful testing of the first HVDC circuit breaker. In its announcement, BPA said the 25-foot-high prototypes of the switch have been built and tested on a fully energized 800 kV segment of the Pacific Intertie.

According to BPA, this achievement was accomplished by applying a "counter voltage" to the HVDC arc formed between the gap in the electrodes. Simultaneously, zinc oxide resistors brought the current to zero, while absorbing a significant part of the energy.

BPA reports that recent advances in metal oxide resistors made this electrical scheme possible.

"The marvelous thing about the two prototype breakers is that they are composed of standard, off-the-shelf components, like a-c circuit breakers, capacitors, and zinc oxide resistors," says Stig Annestrand, BPA's manager of research and development.

This conclusion is confirmed by ASEA's Dr. Long, who was involved in the planning and directing of circuit breaker research for the Department of Energy. He says that this off-the-shelf equipment, assembled in this unique way, makes the d-c circuit breaker readily available for use in HVDC systems.

What is not readily available is a long history of field testing and any demonstrated enthusiasm on the part of electric utilities to experiment with new technologies. "I don't get the feeling the industry is sitting there thinking, 'Let's get something brand new,'" Wayne State's Dr. Meisel said in response to a question on how soon the d-c breaker might be used in HVDC systems.

Harmonic filters effective

Another consideration potentially dampening utility enthusiasm for HVDC systems is the generation of unwanted system harmonics. Harmonics are voltages and currents at frequencies above the standard 60 Hz that characterizes the a-c system in the U.S. Stemming from rectifiers, HVDC converter terminals, and variable speed motor drives, such voltages and currents distort the normal utility sine wave. If severe enough, harmonics can lead to flashovers from insulation degradation and can cause overheating and failure of utility equipment.

Present technology is capable of filtering out these harmonics, researchers say, but the trick is to do it efficiently and in a cost-effective manner. A knowledgeable source at ASEA points out that harmonics are not only generated by d-c conversions but are part of existing a-c systems. Because utilities constructing d-c facilities have to specify technical requirements regarding harmonic filtering, and because these utilities are not always fully knowledgeable about the harmonic content of their a-c systems, often filters are more conservative, and therefore more costly, than they need to be. Consequently, these filters remove even a-c harmonics.

Both GE and ASEA maintain that harmonics themselves have not interferred with the successful operation of HVDC systems.

The Electric Power Research Institute is looking into this question of harmonics and has developed a computer program called HARMFLO for harmonic analysis. Conceptually, a program that models the creation and spread of harmonics can aid the solving of insulation coordination problems as well as addressing concerns in system protection and HVDC filter design and operation.

EPRI claims that its HARMFLO program constitutes a significant improvement over other methods used for harmonic analysis because only power demand and load type need be specified. This means that the harmonic content need not be known before the analysis.

In addition, the program not only calculates the harmonics and how they spread, but how they affect each other.

Even though EPRI is calling the development of this program a "breakthrough," the research organization readily admits HARMFLO's limitations. Since the models used for transmission lines, transformers, motors, generators, and loads are simple, low-frequency models, they are limited to frequency ranges between 60 and 1140 (the 19th harmonic).

There are other limitations as well. Nevertheless, the program is presently usable and accurate, EPRI says, and the research study team is working to improve its efficiency and analytical capabilities.

Harmonic effects increasing

This research is necessary, EPRI maintains, because concern about the effects of harmonics on electric power systems is growing. Such concern is expressed not only over bulk power modes of electricity transport, but over harmonics on subtransmission levels as well.

One of the causes of the increased concern over harmonics has to do with improved network monitoring that has revealed many previously unexplained equipment failures attributable to harmonics.

Another reason is that the sources of harmonics are increasing.

This concern over harmonics, particularly at distribution levels, presents potentially serious problems for electric utilities. These problems range from economic to regulatory to difficulties in consumer relations.

Noting that power system switching is a source of harmonic ripples, Mike Moran of West Texas Utilities observes, "I think everybody is becoming more aware of the switching parameters and the harmonic effects these produce, and this means more technical studies are needed."

Engineers and industry analysts point out that identifying all the varied sources of harmonics and attempting to implement remedial measures could prove difficult and costly. First, a host of consumer appliances (such as the variable speed drill) generate harmonics. Second, as the idea of dispersed generation by non-utility entrepreneurs begins to take hold, the production of electricity by "alternative" generation such as windmills will increase, and this has implications on the quality of line power.

Questions have been raised about these alternative power producers regarding how the quality of their output will be regulated. Should they be free to put out whatever they want? Should they be required to deliver a certain level of quality power? Should the major utility under which these alternative power producers function be required to monitor and possibly clean up the lines? Who is to decide this? How much will it cost?

In addition, there are consumers who, because of technically sensitive applicances like personal computers, desire that power be maintained in a quality state. "The sophistication of the American consumer has gotten to the point where he expects more out of the power system than he expected even five years ago," notes Moran, who is head of the Edison Electric Institute's subtransmission group.

Missouri University professor of electrical engineering Jay D. Morgan concurs. "We are only now beginning to see this as a major problem," he says. He notes that the improvement in the use of electronics, particularly silicon controlled rectifiers, is what potentially threatens to degrade distribution power quality.

Rate treatment foreseen

Dr. Morgan even foresees the possibility that electric utilities, forced to confront this growing menace, would seek rate base treatment for harmonic filtering activities.

In addition, industry organizations such as the Institute of Electrical and Electronics Engineers, in an effort to formulate guidelines for maintaining power quality, may involuntarily lay the base for future regulations in the area.

Bob Bischke of Wisconsin Electric Power Company (WEPCO) has done a lot of work in this area and believes that as consumers experience growing incidents of harmonic interference—such as TV reception distortions—they naturally will expect the local electric company to figure out what is wrong and to fix it.

"This is what will cause utilities to become involved in this," he says.

Bischke notes that although many utilities have special test groups to check out the sources of interference, most utilities are not equipped to do this.

The proliferation of personal computers is what make the problem critical. Better built computers come equipped with uninterruptible power supplies, so that in the event of a power transient or outage, an auxiliary battery power supply automatically kicks in. The computer operator sees no degraded operation.

Customer complaints?

But less expensive PC's do not have such power supplies. Thus, electricity transients or brief outages, which before were met with amiable tolerance by customers, may now be sources of consumer rage.

What makes the problem one of serious concern is the lack of current knowlege about certain aspects of it. Engineers and analysts suspect that there may be harmonic mitigation characteristics inherent in the distribution network. But they have yet to demonstrate this.

"I think we will find that for certain distances and for certain voltages, this will be a non-problem," said Bischke, who is conducting a two year WEPCO study on the issue.

There may be certain classes of customers for whom this is not a problem. Also, for consumers that do experience problems, a simple device may solve it. In addition, once the problem is more clearly identified, it may be easy and inexpensive for appliance manufacturers to add a mitigation component to their products.

But, laments Bischke, "All this is in such infancy, we don't know what to advise manufacturers."

Dr. Narain Hingorani of the Electric Power Research Institute is one who thinks the problem of distribution in line harmonics generally has been overstated. Standards bodies have addressed the generation of harmonics for large installations, Hingorani says, and for smaller systems harmonics simply are not likely to travel very far into the distribution network.

The EPRI researcher says that the distribution line itself has some inherent harmonic filtering capability and thus, although there may be individual situations where a problem exists, it is not likely to become widespread.

In addition, Hingorani notes that appliances themselves are becoming more technologically sophisticated, so that these are less likely to detect harmonics present in the network.

"There is a case here for paying attention," Hingorani concludes, "but not a case for being overly concerned."

6/12/84
C8650-4A

Volume 62, Number 6
June 1984

09635 1984301 W 3 2046
SUITE 800 COPY # 1
STATISTICAL REFERENCE IND
CONGRESSIONAL INFO SVC D
4520 EAST-WEST HWY STE 800
BETHESDA MD 20814

Electric Light & Power

THE NEWS MAGAZINE OF ELECTRIC UTILITY MANAGEMENT AND TECHNOLOGY

WPPSS No. 2 produces power

Washington Public Power Supply System's nuclear plant-2 has been brought into its rated operating conditions. The plant was authorized for full power operation by the Nuclear Regulatory Commission in April. The Atomic Industrial Forum reports that 1984 should be a banner year for new nuclear plants. In recent months, the NRC has authorized full power operation at Commonwealth Edison's LaSalle-2, given Pennsylvania Power & Light's Susquehanna-2 approval to test at five percent power and has issued Pacific Gas & Electric's Diablo Canyon-1 a start-up license.

Rep. Harkin, utility critics seek to kill 'phantom tax' laws that aid financing

WASHINGTON, D.C.—Like frightful spirits at Halloween, the issue of electric company "phantom taxes" has again risen from the corporate grave of dead concerns.

The spectre of the industry losing certain cherished tax benefits has scared utility executives before, but each time they have been successful in sealing up those spirits before they had a chance to become part of federal tax policy.

This time, however, things could be different. Rep. Tom Harkin (D.IA) has taken upon himself the job of chief exorcist, and the House legislator appears committed to doing away with these phantom taxes once and for all.

Utility executives prefer to attribute the financial benefits they currently receive to "deferred taxes" rather than "phantom taxes." But however characterized, the utility industry stands to lose billions of dollars in what amounts to zero interest loans from electricity ratepayers.

"The Phantom Tax Reform Act allows utility commissioners to remove an incentive which not only raises electric rates, but also encourages investor-owned utilities to build power plants costing billions of dollars which may not be needed," Harkin told his fellow legislators earlier this year.

Predictably, utility industry officials disagree with this thesis.

Dollar amounts uncontested

Although one informed Washington observer said that the Edison Electric Insitute, the association of electric utilities, intends to "pull out all the stops" in opposing this legislation, there does not appear to be any disagreement among the contestants over the value of current tax laws to the electric utility industry.

"With the [electric] power industry collecting billions of dollars in phantom taxes annually, the money contained in their deferred tax accounts is skyrocketing," notes the Environmental Action Foundation (EAF) in its April, 1984 analysis of electric utility taxes for 1982.

The EAF, which is the prime mover behind the Harkin tax reform bill, surveyed federal income tax expense data contained in Form 1 annual reports filed with the Federal Energy Regulatory Commission by 150 largest investor-owned electric companies. It was found that at the end of 1982, these utilities were holding $19 billion in accumulated deferred taxes and $10.4 billion in accumulated deferred investment tax credits (ITC's)—a total of $29.4 billion.

The EAF report then quotes a figure, attributed to EEI, representing *current* accumulated revenues—$34 billion. This figure was confirmed by an EEI spokesman.

The EAF calculates that in effect electric utilities are therefore collecting $405 from every household in the U.S. and holding that money for extended periods for their own use.

Continued on page 25

N.J. commission withdraws penalty as EPRI agrees to 'support' U.S. research

When is a commitment not a commitment?

Dan Utroska
Associate Editor

Agreement appears to have been reached between the Electric Power Research Insitute and the New Jersey Board of Public Utilities over the granting of EPRI funds to support feed pump research by American pump suppliers.

A controversy over EPRI contractual procedures arose last March when the BPU, angered by the fact that EPRI had awarded a $5.7 million research contract to a Swiss pump company at the expense of New Jersey and other American companies, disallowed the full cost of the contract in the annual expenses of Public Service Electric & Gas Company.

Specifically, the board prohibited company use of money collected from ratepayers for PSE&G membership in EPRI up to the full $5.7 million value of the research contract (see *EL&P*, May 1984, page 1).

Believing that it has now extracted from EPRI a commitment to support domestic research in feed pump technology by approximately the amount of the original foreign contract, the New Jersey BPU has withdrawn its opposition to the payment of $5.7 million in membership fees by PSE&G.

The extent to which EPRI has agreed to support American pump research has become a critical component in the apparent resolution of the conflict.

BPU Commissioner Edward Hynes, who had led the board's inquiry in EPRI's contract procurement policies, reads the EPRI declaration of support as "a total commitment to fund this [pump research] consortium."

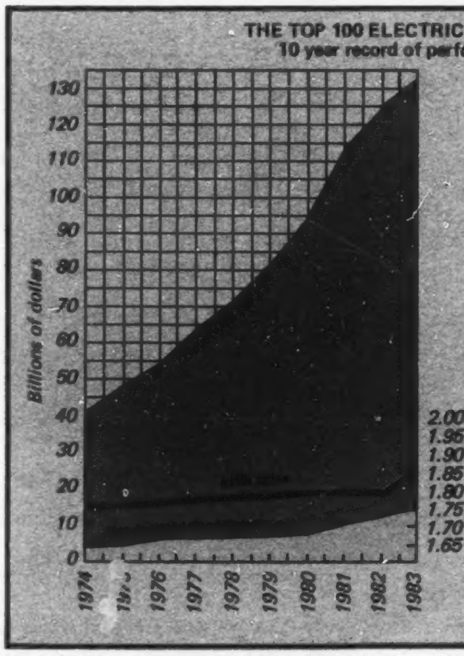
As reported, a research group has been formed by five American pump suppliers. The consortium, called Pradco (Pump Research and Development Co.), reportedly had been in discussion with EPRI to obtain partial funding for its work when the New Jersey board declared its sanctions against Public Service Electric & Gas. Presently, the group is awaiting approval from the Justice Department concerning anti-trust matters.

In response to the New Jersey board's action escrowing PSE&G membership fees to EPRI, institute president Floyd L. Culler on April 4 wrote to Hynes outlining the research organization's support for the pump research consortium.

"...[T]he prospects for improvements in feed pump reliability are of sufficient importance to the electric utility industry that EPRI is clearly committed to pursuing such a program with Pradco, or with individual U.S. companies if Pradco fails to materialize," Culler said in his letter.

"We have not been able to arrive at firm cost because we have no project estimates from Pradco and must still reach a mutual agreement on a program that the pump companies and EPRI consider to be useful and pro-

Continued on page 16



THE 19TH ANNUAL TOP 100 ELECTRIC UTILITIES report, which begins on page 19, shows the continued improvement in sales and financial performance during 1983. Following the 1982 sales decline reported a year ago, the Top 100 electric utilities' sales bounced back in 1983 and Revenues and Net Income available for common shares both rose. The chart at left shows the 10-year trends for these three vital areas. Revenues increased to $132 billion and Net Income for Common rose to $14.6 billion. Sales climbed 2.2 percent to 1.84 trillion kWh as the result of favorable weather and stronger industrial activity.

Foreign Power Briefs

- **Seventeen companies** representing the utilities and reactor manufacturing and engineering industries of Japan have agreed to contribute $18 million to the U.S. Department of Energy's Three Mile Island Unit 2 research and development program. DOE said that the Japanese companies also agreed to provide approximately 100 man-years of engineering assistance over the next five years. Up to 22 Japanese engineers and scientists will participate in the TMI-2 R&D activities. Assistant Secretary for Nuclear Energy Shelby T. Brewer said, "Our success in gaining Japanese participation in the TMI-2 R&D effort is an example of our intent to continue to press toward major international collaboration efforts related to nuclear energy. In this way, individual nations need not bear the full cost of expensive R&D efforts and the benefits obtained are more widely available."

- **The Egyptian Electric Authority** has awarded a $117-million contract to General Electric Company for the construction of a 150,000-kW steam plant. GE said the plant will supply electricity to the Ismailia and Suez regions of the country. The power plant is scheduled to go on-line in late 1986. GE said the contract was largely funded by the U.S. Agency for International Development.

- **The Atomic Industrial Forum** (AIF) reports that 20 new nuclear power plants went into service in ten foreign countries last year. AIF says there are now 227 nuclear reactors abroad. Six new reactors were ordered in foreign countries last year. AIF President Carl Walske said the growth in nuclear power abroad "demonstrates that the world commitment to nuclear energy is solid, and that nuclear electricity will continue to make a vital contribution to the economy abroad as well as in this country." The AIF said that its annual survey of nuclear power outside the U.S. found that nuclear capacity grew nearly 15 percent from 105,283 MW to 120,823 MW last year, nearly double 1982's growth rate. New reactors went into operation in France (five), the Soviet Union (four), Canada, South Korea and Spain (two each), and one each in Argentina, Belgium, Hungary, Sweden and India.

- **Ontario Hydro's** Pickering Unit 6 was placed into service in February, two months ahead of schedule. The utility reports the unit had been undergoing extensive testing since November of last year.

- **Asia's second largest transmission line**, a $400-million, 500-kV line in Pakistan, was inaugurated in April by Pakistan President General Muhammad Zia-ul-Haq, reports Hazra Engineering Company, engineering consultant for the project. Built by Pakistan's Water and Power Development Authority, the 1,300-kilometer line runs north to south across the country, starting at the Tarbela hydroelectric power station and terminating at Jamshoro in the Province of Sind. The project was divided into three stages. The first was completed in 1979 and the second stage in 1981. This month, a 220-kV line will connect the project with Karachi, Pakistan's largest city.

- **The Spanish government** has told utilities to put aside almost 7 percent of their revenues as insurance to offset rising debts. *The Wall Street Journal* reports that Industry Minister Carlos Solchaga said utilities must deposit 2.8 percent of their overall sales into a fund to guarantee they will remain solvent. Solchaga also ordered the utilities to increase their contributions to a fund used to finance nuclear investments to 3.9 perent of revenue from 2.89 percent.

In This Issue

Editorial 4

Calendar.................... 13

19th Annual Top 100 Electric Utility Report focuses on the sales and financial achievements of the nation's largest investor-owned electric companies. 19

Electric utility fleet managers soon may have to decide whether to include electric vehicles in their fleets. 25

Superconducting generator development in the U.S. is winding down as utilities appear to lose interest.**G** 34

Results are in from the first cooperative project at EPRI's transmission tower test facility.**T/D** 38

Utility interest in large-scale fuel cells appears to be picking up with several new installations planned.**G** 53

Readers' Service 71

New Products 74

Bulletin Board.................... 77

Personnel 79

Regulatory Review 80

Management Methods 82

EL&P readers whose responsibilities include both Generation and Transmission/Distribution receive both technology sections. Other readers receive the technology section that applies to their respective area of responsibility. The Generation edition is indicated by a single dot (•) in the upper right corner of page 1; the T/D edition carries two dots (• •). All readers receive EL&P's industry news section.

Industry tries to refocus public relations programs

EEI admits ad campaign was ill-conceived

Dan Utroska
Associate Editor

Amidst the admission by the Edison Electric Institute that its earlier media ad campaign against utility regulators was ill-advised, and the growing scrutiny of electric company expenditures, by the regulatory community itself the electric utility industry is working hard to come up with a program that will improve public opinion and help pave the way for the construction of more nuclear power plants.

Referring to EEI's 1981-82 ad campaign aimed at regulators, EEI Senior Vice President for Economics and Finance Douglas C. Bauer said, "It's my personal position that if we had those ads to do again, we wouldn't do them. I think it was a mistake."

Testifying on April 11, 1984 on behalf of Florida Power & Light Company before the Florida Public Service Commission, Bauer was pressed on the matter by state commissioner John R. Marks, III. "Now, we know your personal position on it. What is EEI's position on it?" he asked.

"I have a certainty of 0.9 or above that that's my boss' position, and I don't know beyond that...," Bauer said. [In probability calculations, 1.0 is a surety.]

In November, 1981, a two-page spread in which former state utility regulatory commissioner Charles J. Cicchetti declared, in part, that electric utilities had become political scapegoats and that this largely was attributable to "restrictive regulatory policies and procedures" was the first salvo in a multi-million media advertising blitz aimed at state regulators.

The ad had been sponsored by the Edison Electric Institute.

"Adverse Regulation Hinders Utilities in Capital Markets," *The Wall Street Journal* boomed in 96-point type on January 14, 1982. "Electric Utility Users Will Pay For Adverse Utility Regulation," *The Wall Street Journal* screamed on February 9. And on April 12, the message was "Everyone Pays for Adverse Utility Regulation."

The messages carried a common refrain: rates of return allowed to utility companies by state regulators were too low to permit economical access to capital markets for new plant and to enable companies to assure customers an adequate, reliable source of electricity for the future.

Addressing the lessons from that ad campaign, EEI's Doug Bauer said, "But I think we have learned a lot from that...and I think you will see that the themes that are occurring now are not those kinds of themes. They are themes that we think are more balanced and helpful in the effort of connecting with customers and getting sensible things to happen."

Included in these new themes is one that seeks to communicate to ratepayers the value of electricity, Bauer said in earlier testimony. "It's important," he said, "...that if people understand that when they turn a lightswitch on they're making a choice, [then] that is going to help ...the company to connect with its customers and undertake those kinds of demand side activities, including load management and load shifting, that can help lessen the bill of the customer."

Other elements also are to be part of this new approach, Bauer said. Pointing out to customers, for example, how captive shipping of coal can raise electric rates and how the industry is working to counter such escalations, is seen to be primarily in the interest of ratepayers and is to be part of EEI's on-going Media Communications Program.

Ramifications still occurring

Unfortunately for the electric utility industry, it may be considerably easier to turn around a public relations program than to sidestep the deleterious effects of a previously ill-conceived one.

The day after EEI's first media blitz program in November, 1981 one regulator attending the NARUC conference was asked his response to the institute's program. After pointing out that the ad campaign was an inappropriate way to reach the public because the ads were not sufficiently fundamental to describe what the so-called financial crisis was all about, this regulator offered, "I'll now begin to scrutinize more carefully utilities' constributions to EEI."

Full-blown investigation

Such a sentiment has now ripened into a full-blown investigation, at the national level, on how much of EEI dues ought to be recoverable from ratepayers (see *EL&P*, February 1984, page 1 and April 1984, page 1).

The most recent development in this on-going probe is EEI's March 1 letter to John Gibbons, chairman of the NARUC Staff Subcommittee on Accounts. The subcommittee is conducting the inquiry. The letter reveals the amounts that EEI has contributed to the U.S. Committee on Energy Awareness and how ratepayers have in part funded EEI's new national marketing program, "Electricity: It's the Power of Choice."

NARUC investigators have been very interested in the relationship of EEI and CEA and whether or not CEA has been getting money for use in pro-nuclear advertising from the nation's ratepayers. EEI vehemently maintains that funds collected from member utilities and distributed to CEA are voluntary contributions and are not collected as part of member companies' dues.

$9.3 million contributed

The March 1 letter shows that from 1979 through 1981 some $9.3 million was contributed to CEA via the budget of the Utility Nuclear Power Oversight Committee (UNPOC) set up by the industry after the Three Mile Island accident to represent the entire electric utility industry in issues of concern.

According to EEI's Douglas Bauer, who authored the letter to Gibbons, UNPOC solicited funding to support advocacy of these generic issues, although this money was "independent of EEI dues."

"EEI administered only the portion of UNPOC funds provided by investor-owned utilities [as opposed to the public power sector or co-operatively-owned utilities] and some contributions from concerned vendors."

In 1982, $2.5 million was contributed to CEA from EEI, but here too, EEI maintains that this money was contributed from its Media Communi-

Continued on page 67

19th Annual Top 100 Electric Utilities Report

Most major utilities' 1983 performances improved; financial positions strengthened

Robert A. Lincicome
EL&P Editor-in-Chief

1983 was a good year for most of the the nation's Top 100 investor-owned electric utilities. For most, the improvement continued from where 1982 left off. Blessed with an improving economy, favorable weather conditions, rate relief on prior-year results and the effect of continued cost-control measures, most of the Top 100 were able to improve their financial positions from those posted for the previous year.

The strong performance of the Top 100 electric utilities in 1983 reflected the third consecutive year of improvement.

The performance of the Top 100 electric utilities during the year started slowly, limped along until a pickup began in June fueled by both an early summer heat wave and improvement in industrial activity, continued to gain through the third quarter and into the fourth quarter, and then received another boost from exceptionally cold weather in December to finish the year strongly.

While overall performances were good in 1983, there were, however, areas of continuing concern. One of these was an increase in the portion of net income available for common stockholders represented by allowance for funds used during construction (AFUDC). AFUDC contributes to earnings, on paper, but produces no cash flow and thereby depreciates the quality of a utility's earnings. In some cases, AFUDC represents more than 100 percent of a utility's earnings, which in some cases has contributed to (at least) short-term cash crunches for the utility managements involved. The bright side of this development is that, according to the Edison Electric Institute, the rate of increase in AFUDC from quarter to quarter appeared to be declining as the year concluded.

Also, although the total amount of long-term debt increased during the year, 30 of 99 reporting utilities actually reduced their long-term debt and 61 of 99 reporting utilities reduced the portion of net utility plant covered by debt.

The Top 100 electric utilities produced total revenues of $132.0 billion in 1983. This represents a new record and is 7.0 percent ahead of 1982 revenues. This represents largely the impact of more-severe-than-normal weather and the mid-year resurgence of industrial activity, especially in the heavily-industrialized north central states. The increase in revenues also reflected rate increases granted by state public utility commissions to rate requests on earlier test years. In addition, the revenue figure also included collections made under fuel adjustment clauses and the net effects of subsidiary activities.

These higher revenues resulted from record sales of 1.843-trillion kilowatthours.This total was 2.2 percent ahead of 1982 and marginally ahead of the previous sales record of 1.842 kWh achieved in 1981. KWh sales had declined in 1982 for the first time since initiation of the Top 100 electric utilities survey in 1966.

The 2.2 percent in kWh sales came on an increase in the total number of customers of more than 1.2 million or 1.7 percent over 1982.

Net incomes of the Top 100 electric utilities climbed in 1983 to $14.6 billion, an increase of 18.7 percent. That net incomes increased substantially faster than revenues is a reflection of the continued cost-control efforts of utility managements and overall increased utility productivity, despite fuel costs that were up slightly. The gain, however substantial, was the lowest in the last three recovery years. In 1981, net incomes increased 22.2 percent. In 1982 the increase fell to 20.6. The gain of 18.7 percent in 1983 reflected both the increase in shares outstanding and the maturation of the recovery.

Per-share earnings were up 8.0 percent, to an average $3.24 per share. In 1982, earnings increased 6.4 percent to $3.00 per share. In 1981, the first year of substantial recovery for the Top 100 electric utilities, earnings were $2.52.

Kilowatthour sales by the Top 100 electric utilities bounced back in 1983, increasing 2.2 percent, the same nominal amount they fell a year earlier. The recovery, however, was fractionally larger than the decline in 1982 and pushed total sales to a new record of 1.843 trillion kWh, marginally ahead of the previous record of 1.842 trillion kWh established in 1981.

The first quarter of 1983 was characterized by milder-than-normal weather and the continued recessionary level of industrial activity, with all levels of kWh sales down from the first quarter of 1982. During the second quarter of the year, industrial ac-

EARNINGS GROWTH STATISTICS

Company Name	Rank	% Change From 1982	1983 Earnings Per Share	Company Name	Rank	% Change From 1982	1983 Earnings Per Share
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Missouri Public Service	6	50.99	$3.05	Toledo Edison	56	7.03	$3.50
Kansas City Power & Light	7	48.75	$4.15	Cincinnati Gas & Electric	57	6.91	$2.94
Iowa Public Service	8	47.11	$3.31	Iowa-Illinois Gas & Electric	58	6.33	$4.20
Northeast Utilities	9	34.86	$2.37	Dayton Power & Light	59	5.66	$2.80
Louisville Gas & Electric	10	29.86	$2.87	Middle South Utilities	60	5.58	$2.46
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Detroit Edison	16	26.29	$2.21	Public Service Electric & Gas	66	4.94	$3.40
Southern Indiana Gas & Electric	17	25.15	$4.28	Niagara Mohawk Power	67	4.92	$2.77
Illinois Power	18	25.00	$3.80	Arizona Public Service	68	4.85	$3.46
Eastern Utilities Associates	19	24.44	$2.80	Oklahoma Gas & Electric	69	4.28	$2.68
Central Maine Power	20	24.26	$2.51	Ohio Edison	70	4.23	$2.22
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Southern California Edison	26	21.25	$6.22	Orange & Rockland Utilities	76	1.93	$2.64
American Electric Power	27	20.20	$2.44	Texas Utilities	77	1.30	$3.90
Florida Power Corporation	28	20.00	$2.64	Carolina Power & Light	78	1.26	$3.21
Empire District Electric	29	18.96	$2.51	Central Hudson Gas & Electric	79	0.77	$3.94
Gulf States Utilities	30	18.46	$2.31	Hawaiian Electric	80	0.49	$4.12
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Central Louisiana Electric	36	15.38	$2.85	Interstate Power	86	–2.44	$2.40
Delmarva Power & Light	37	15.02	$2.45	Montana-Dakota Utilities	87	–4.18	$3.90
Rochester Gas & Electric	38	14.95	$3.23	Idaho Power	88	–4.46	$4.50
Tampa Electric	39	14.18	$3.14	Washington Water Power	89	–4.73	$3.02
Southern Company	40	13.45	$2.70	Pennsylvania Power & Light	90	–8.66	$3.06
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
San Diego Gas & Electric	46	10.34	$3.20	Sierra Pacific Power	96	–22.73	$1.70
Wisconsin Electric Power	47	10.28	$3.97	Nevada Power	97	–33.17	$2.74
South Carolina Electric & Gas	48	10.10	$2.29	Tucson Electric Power	98	–33.96	$5.37
Public Service of New Mexico	49	9.63	$3.53	Pacific Power & Light	99	–85.15	$0.45
Otter Tail Power Company	50	9.59	$3.20	Centel	100	N/A	N/A

SALES DATA

Company	1983 Total Sales (KWH)			1983 Sales (KWH) By Type of Customer (% of Sales)				Average Annual Residential Use		Ratio of Long Term Debt to Net Plant	
	Rank	% Increase	Average Annual Growth 1978 – 1983	Resid.	Comm.	Ind'l.	Other	1983	1982	1983	1982
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Orange & Rockland Utilities	6	9.21	−0.30	30.8	20.2	27.2	21.8	6,174	5,827	42.1	43.1
Delmarva Power & Light	7	8.88	0.00	27.1	23.4	33.0	16.5	8,109	7,860	43.0	44.0
Iowa Resources	8	8.30	−0.42	41.0	24.5	32.1	2.4	9,201	8,279	42.6	43.4
Kansas City Power & Light	9	8.23	−0.69	31.1	40.1	23.3	5.5	8,774	7,764	88.5	81.1
Iowa-Illinois Gas & Electric	10	7.85	−0.23	25.2	25.4	42.5	6.9	6,677	6,027	35.4	37.9
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Minnesota Power & Light	16	6.58	−2.38	10.3	8.8	61.1	19.8	7,874	7,928	43.0	47.7
Consolidated Edison	17	6.48	0.36	26.1	58.9	4.3	10.7	3,427	3,199	37.8	39.3
Niagara Mohawk Power	18	6.41	0.16	24.7	27.0	31.3	17.0	6,887	6,878	44.4	47.3
Illinois Power	19	5.98	0.59	27.5	17.4	43.7	11.4	8,671	8,051	41.6	41.2
Northern States Power	20	5.84	0.16	27.7	13.8	40.4	18.2	7,621	7,337	39.6	37.5
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Public Service Electric & Gas	26	5.57	−0.13	27.3	38.2	32.9	1.5	5,602	5,156	71.7	42.6
Rochester Gas & Electric	27	5.55	−0.55	28.6	22.2	23.9	27.3	6,710	6,671	47.6	46.1
Southern Company	28	5.39	2.24	24.1	18.5	34.4	23.0	10,404	10,398	49.7	53.0
Duke Power	29	5.39	0.58	25.3	19.1	38.6	16.0	12,278	12,065	44.6	42.5
Central Hudson Gas & Electric	30	5.05	3.17	22.4	20.1	22.9	34.6	6,208	6,142	80.0	78.5
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Consumers Power	36	4.69	−0.83	31.7	25.0	39.5	3.9	6,763	6,587	102.8	78.2
Public Service of New Hampshire	37	4.66	1.73	28.6	11.7	28.6	31.0	6,944	6,946	44.8	45.0
Atlantic Electric	38	4.64	1.56	43.5	34.5	20.9	1.0	7,715	7,444	42.7	41.9
Indianapolis Power & Light	39	4.48	−0.04	32.2	21.5	45.4	0.9	9,903	9,417	40.2	37.0
Wisconsin Public Service	40	4.46	2.24	26.5	23.4	31.0	19.1	7,163	7,025	34.4	34.6
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Cincinnati Gas & Electric	46	3.64	1.33	35.6	23.6	31.1	9.7	9,889	9,570	46.8	48.5
Texas-New Mexico Power	47	3.45	4.26	27.0	20.2	49.6	3.2	9,757	10,322	41.5	42.5
Pennsylvania Power & Light	48	3.41	0.41	35.3	26.5	33.1	5.1	9,061	9,039	42.7	46.1
Commonwealth Edison	49	3.36	−1.50	30.3	31.6	27.1	10.9	6,798	6,310	43.2	47.3
United Illuminating	50	3.28	−1.01	35.4	35.9	27.2	1.5	6,336	6,213	38.6	44.1
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Kentucky Utilities	56	2.79	0.27	31.7	19.4	18.0	30.9	10,724	10,304	39.6	42.4
El Paso Electric	57	2.76	−0.28	27.1	29.4	18.0	25.5	5,839	5,869	40.9	39.8
Idaho Power	58	2.10	3.30	21.4	20.5	24.4	33.7	14,066	14,939	43.2	43.6
Montana-Dakota Utilities	59	2.03	5.35	42.2	23.9	30.1	3.9	7,900	7,972	40.5	36.7
Hawaiian Electric	60	1.63	−0.35	27.9	22.0	24.7	25.4	6,752	6,815	39.2	39.4
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Central Vermont Public Service	66	1.02	6.35	34.0	8.4	30.9	26.7	7,858	7,880	52.8	50.0
Southern California Edison	67	0.95	0.81	28.7	31.2	30.9	9.3	5,879	5,685	44.9	47.3
American Electric Power	68	0.75	0.59	23.0	14.7	31.7	30.6	10,098	9,898	50.0	54.5
Central Illinois Public Service	69	0.59	0.32	26.6	10.7	39.0	23.7	8,671	8,328	37.3	37.5
General Public Utilities	70	0.56	0.05	34.6	26.4	33.6	5.4	7,535	7,419	46.8	51.2
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Gulf States Utilities	76	0.13	0.05	19.6	15.0	58.0	7.5	12,097	13,015	83.6	81.9
Public Service of Indiana	77	0.12	0.31	28.2	20.9	33.2	17.7	10,479	10,411	76.0	38.5
Otter Tail Power	78	−0.13	7.32	25.6	13.3	30.7	30.4	9,862	10,008	37.8	38.9
Washington Water Power	79	−0.20	0.64	32.4	18.7	15.0	33.8	14,166	15,221	54.1	47.3
San Diego Gas & Electric	80	−0.28	2.25	36.2	34.6	24.0	5.2	5,382	5,388	44.5	74.5
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Arizona Public Service	86	−1.52	3.74	32.0	32.9	18.7	16.4	10,357	9,840	43.9	43.4
Central Illinois Light	87	−1.83	−2.54	34.7	23.5	39.4	2.4	8,676	8,384	40.3	38.0
Middle South Utilities	88	−2.01	−0.20	30.7	[illegible]	41.8	8.1	11,060	11,306	49.1	49.7
New York State Electric & Gas	89	−2.14	1.08	35.8	[illegible]	21.9	21.7	7,223	7,306	46.0	49.3
Houston Lighting & Power	90	−2.31	2.49	23.4	18.1	52.4	6.1	11,759	13,501	39.3	41.1
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Savannah Electric & Power	96	−6.51	−0.28	41.2	30.1	24.8	3.9	10,148	10,019	49.2	58.2
Philadelphia Electric	97	−6.71	1.58	30.7	11.9	52.5	4.9	6,990	6,544	46.5	46.9
Puget Sound Power & Light	98	−7.32	2.65	48.3	25.2	15.9	10.6	13,970	15,143	49.3	47.7
Interstate Power	99	−7.91	2.48	24.3	17.6	51.0	7.1	7,373	7,055	48.5	49.3
Commonwealth Energy System	100	−10.01	−1.37	27.2	26.4	10.4	36.0	5,671	5,558	40.8	40.4

tivity began to pick up, but continued milder-than-normal (and milder than a year earlier) weather held total kWh sales gain to barely in-the-black numbers. However, a heat wave rolled across the country at the end of the second quarter and continued over into the third quarter, when warmer than normal summer weather was coupled with the continued improvement in the economy, especially in the Southeast and heavily industrialized Midwest, to bump both demand and energy sales upward. There was a moderation of growth during the first two months of the fourth quarter of the year, but then a frigid sweep of Arctic temperatures hit the country and pushed sales rapidly upward again to a new record.

TABLE I
THE TOP 10 IN KWH SALES

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1	2	Southern Company	102,008	5.4
2	1	American Electric Power	98,271	0.8
3	4	Texas Utilities	62,710	3.9
4	6	Commonwealth Edison	61,217	3.4
5	3	Pacific Gas & Electric	60,012	−0.7
6	5	Southern California Edison	59,893	1.0
7	7	Houston Lighting & Power	55,228	−2.3
8	9	Duke Power	54,151	5.4
9	8	Middle South Utilities	50,422	−2.0
10	10	Florida Power & Light	48,589	3.2

Fourteen utilities reported sales gains in excess of the historic 7 percent rate. Seventy-seven reported positive changes in kWh sales, in sharp contrast to 1982 when 69 posted declines. Median change in 1983 was +3.22 percent, compared with a -1.97 percent change in 1982.

The 10 companies reporting the largest sales are shown in Table I.

Average residential use increased 1.5 percent in 1983, or 130 kWh. The total was 8607 kWh. Although the increase was small, it was substantially better than a year earlier, when the increase was a mere 9 kWh. Since average residential uses declined by 303 kWh in 1981, the 1983 residential usage remained some 175 kWh lower than in 1980.

As has been historically true, the companies reporting the highest average residential electrical usage lie in the Far West, where electricity costs are relatively low and in areas where heat and humidity combine to make summer weather miserable without air conditioning. Leaders, nationally, were: 1) Washington Water Power, 14,166 kWh (−6.9 percent); 2) Idaho Power, 14,066 kWh (−5.8 percent); 3) Puget Sound Power & Light, 13,970 kWh (−7.7 percent); Nevada Power, 13,445 kWh (−2.0 percent) and 5) Duke Power, 12,278 kWh (+1.8 percent).

Conversely, the utilities reporting the lowest average residential electrical usage were located where electricity rates were high. Those with the lowest uses were: 100) Consolidated Edison, 3427 kWh (+7.1 percent); 99) San Diego Gas & Electric, 5382 kWh (-1.1 percent); 98) Boston Edison, 5407 kWh (+3.5 percent); 97) Public Service Electric & Gas, 5602 kWh (+8.7 percent) and 96) Duquesne Light, 5752 kWh (+1.5 percent).

Revenues totaled $132.0 billion in 1983. This represents a gain of 7.0 percent. Although the increase was a solid one, it must be pointed out that it is the smallest revenue gain posted by the Top 100 electric utilities in more than a decade. In 1982, revenues gained 9.5 percent and the year previous the increase was 20.3 percent. With kWh sales up just 2.2 percent, the majority of the revenue gain is the product of rate relief.

Only nine utilities reported decreases in revenues, all on flat or negative changes in kWh sales from 1982.

The largest revenue gains were reported by Kansas Power & Light (+78.5) on the strength of a 5.0 percent increase in sales; Central Illinois Power +24.9 percent) on essentially flat kWh sales from 1982; and Southern Indiana Gas & Electric (+22.7 percent) on sales increase of 26.1 percent. KP&L's increase came from a large increase in gas-revenues, although its electric revenues were off in 1983.

At the opposite end of the scale, the companies reporting the biggest revenue declines were: 100) Hawaiian Electric (-9.4 percent) on a small 1.6 percent increase in kWh sales; 99) Public Service of New Mexico (-6.8 percent) on a 6.0 percent decrease in kWh sales and 98) Montana-Dakota Utilities (-5.7 percent) on a 2.0 percent sales gain.

A total of 42 utilities reported company revenues in excess of $1 billion for 1983, the same as for 1982. The ten largest revenue producers are shown in Table II and are the same companies that led the nation a year ago. The first three utilities and the last four ranked the same in 1983 as in 1982. The others reflected small changes in rankings.

Although revenue gains in 1983 were the lowest in more than a decade, net incomes available for common shareholders increased substantially. In fact, the increase in net income for common, at 18.7 percent, was the third highest in a decade and serves as a testimonial to the effectiveness of the stringent cost control measures imposed by utility managements in the past year.

Overall, 89 utilities reported increases in net incomes for common, 10 suffered declines and one reported no data. A year ago, 88 utilities posted gains, 11 declines and one reported no data.

There remains a problem with net incomes, however, and that continues to be the size of the portion of net income represented by allowance for funds used during construction. In some cases, AFUDC, which is essentially a bookkeeping transaction, represents more than the total of net income for common. Since AFUDC does not generate any cash, companies with AFUDC greater than total

TABLE II THE TOP 10 TOTAL REVENUES

[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1	1	Pacific Gas & Electric	$6.647	−2.0
2	2	Consolidated Edison	5.512	8.8
3	3	Southern Company	5.418	9.9
4	6	Commonwealth Edison	4.634	12.2
5	4	Southern California Edison	4.466	3.8
6	5	American Electric Power	4.368	4.5
7	7	Public Service Electric & Gas	3.963	
8	8	Houston Lighting & Power	3.524	1.3
9	9	Texas Utilities	3.488	7.7
10	10	Florida Power & Light	3.353	6.8

In addition, 32 companies reported total revenues in excess of $1-billion, but less than $3-billion.

FINANCIAL STATISTICS

Company	Net Income		Revenue		Sales (KWH)		Int. Cov. Ratio		Earnings Per Share	Price/Share 1983 (Dollars)		% Change Long Term Debt
	Rank	% Gain	Rank	% Gain	Rank	% Gain	1983	1982	1983	High	Low	1983
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Public Service of New Hampshire	6	70.8	48	8.1	37	4.7	2.85	1.88	$3.49	20.000	10.875	27.85
Kansas City Power & Light	7	67.2	20	11.7	9	8.2	5.71	3.64	$4.15	22.500	16.750	9.97
Missouri Public Service	8	54.9	10	15.5	15	6.8	2.84	2.06	$3.05	18.000	13.250	−14.38
Iowa Public Service	9	52.6	73	4.5	65	1.1	2.08	1.49	$3.31	27.000	21.500	−1.59
Eastern Utilities Associates	10	49.7	69	4.9	45	3.8	2.46	1.85	$2.80	18.375	13.875	28.30
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Gulf States Utilities	16	42.3	30	9.9	76	0.1	1.81	0.96	$2.31	16.250	12.375	15.31
Union Electric	17	39.2	11	15.1	13	7.6	1.87	1.49	$2.66	16.250	12.250	5.38
Commonwealth Edison	18	37.2	18	12.2	49	3.4	1.77	1.26	$4.39	29.250	24.500	0.28
Illinois Power	19	34.9	9	15.5	19	6.0	3.41	2.74	$3.80	24.125	19.375	10.67
Central Illinois Public Service	20	34.4	2	24.9	69	0.6	2.20	4.10	$2.33	17.125	13.750	−1.00
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Montana Power	26	31.8	94	−1.9	94	−5.7	1.49	1.21	$4.22	30.375	25.125	7.42
Florida Power Corporation	27	31.2	25	10.5	22	5.6	1.94	1.45	$2.64	21.500	18.375	−0.37
Kansas Gas & Electric	28	30.5	19	12.0	72	0.3	4.78	3.79	$3.08	21.375	16.500	22.72
Duquesne Light	29	30.4	56	7.2	81	−0.4	1.46	1.21	$2.20	18.250	13.000	10.54
Iowa Resources	30	28.7	6	18.7	8	8.3	2.98	2.43	$4.46	29.575	24.500	0.85
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Rochester Gas & Electric	36	27.3	22	10.9	27	5.6	4.79	3.61	$3.23	18.500	17.250	19.57
Wisconsin Public Service	37	27.2	51	7.8	40	4.5	3.32	2.28	$3.89	30.500	22.250	−4.11
Public Service of New Mexico	38	26.8	99	−6.8	95	−6.0	2.00	1.98	$3.53	29.625	22.750	20.04
Indianapolis Power & Light	39	26.8	54	7.5	39	4.5	3.19	2.52	$4.17	30.625	25.625	19.10
Ohio Edison Company	40	25.5	66	6.0	63	1.3	0.93	0.69	$2.22	16.125	12.250	6.28
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Consumers Power	46	22.4	37	9.1	36	4.7	1.44	1.23	$3.12	21.875	13.125	12.76
San Diego Gas & Electric	47	21.9	60	6.9	80	−0.3	3.18	2.36	$3.20	22.000	17.000	32.02
Middle South Utilities	48	21.7	86	2.2	88	−2.0	1.20	0.99	$2.46	16.750	13.125	13.61
Cleveland Electric Illuminating	49	21.6	36	9.2	53	2.9	2.77	2.51	$3.28	23.000	16.625	5.34
South Carolina Electric & Gas	50	21.4	8	15.6	31	5.0	2.94	2.22	$2.29	21.250	17.500	−7.68
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Consolidated Edison	56	18.5	40	8.8	17	6.5	5.48	4.25	$4.16	25.875	19.000	−1.78
Northern States Power	57	18.2	43	8.6	20	5.8	4.26	3.70	$5.60	40.750	29.750	8.18
Wisconsin Power & Light	58	17.4	46	8.4	4	10.9	4.49	3.44	$3.97	29.125	23.000	−2.63
Niagara Mohawk Power	59	17.0	28	10.0	18	6.4	1.97	1.97	$2.77	18.500	15.250	6.55
Southwestern Public Service	60	16.0	5	19.5	23	5.6	3.10	2.97	$2.39	19.750	15.625	6.05
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Washington Water Power	66	14.6	97	−2.3	79	−0.2	5.88	4.63	$3.02	22.750	18.500	26.40
Cincinnati Gas & Electric	67	14.6	44	8.6	46	3.6	2.09	1.99	$2.94	19.375	11.875	2.52
Central & South West	68	14.2	34	9.3	73	0.2	2.97	2.82	$3.02	20.750	16.375	7.64
Otter Tail Power	69	13.8	78	3.5	78	−0.1	2.86	2.35	$3.20	25.875	21.250	−1.64
Minnesota Power & Light	70	13.6	81	2.7	16	6.6	2.59	2.32	$3.82	27.875	23.250	−0.03
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Utah Power & Light	76	9.8	35	9.3	74	0.2	2.00	1.70	$2.39	25.000	20.750	−4.34
Duke Power	77	9.7	38	9.1	29	5.4	2.92	2.64	$3.77	26.375	21.750	1.24
New York State Electric & Gas	78	8.8	75	4.2	89	−2.1	1.81	1.96	$3.06	22.875	19.125	12.12
Central Illinois Light	79	8.5	33	9.4	87	−1.8	3.46	3.42	$2.87	23.000	18.630	−0.02
Idaho Power	80	8.1	85	2.3	58	2.1	2.88	2.47	$4.50	34.875	28.500	3.58
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Puget Sound Power & Light	86	4.5	23	10.9	98	−7.3	1.68	1.46	$1.93	16.500	13.125	9.91
Hawaiian Electric	87	4.3	100	−9.4	60	1.6	2.27	1.58	$4.12	33.875	27.250	1.16
Florida Power & Light	88	1.3	64	6.8	51	3.2	2.16	2.10	$5.02	42.250	35.000	7.76
Interstate Power	89	0.9	67	5.9	99	−7.9	2.65	2.60	$2.40	18.000	15.375	−0.13
Centel	90	0.0	4	21.4	33	4.9	N/A	N/A	N/A	N/A	N/A	N/A
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Sierra Pacific Power	96	−12.0	74	4.4	93	−4.9	1.63	1.47	$1.70	15.500	13.125	21.11
Portland General Electric	97	−18.3	96	−1.9	92	−4.1	1.36	1.58	$1.87	16.625	13.125	−5.41
Nevada Power	98	−19.7	61	6.9	84	−1.2	1.67	2.18	$2.74	30.000	25.000	−9.28
Tucson Electric Power	99	−32.2	62	6.9	91	−3.0	4.03	6.51	$5.37	40.250	24.626	60.44
Pacific Power & Light	100	−83.8	14	13.7	85	−1.3	0.97	1.40	$0.45	25.500	20.000	3.35

ALPHABETICAL LISTING OF COMPANY PERFORMANCES

			Customers Served							
	Electric Sales		Electric		Gas		Revenues			Net Income
Company	Rank	KWH Sales (millions)	Total (1,000's)	% Gain	Total (1,000's)	% Gain	Total (1,000's)	% Electric	% Gas	After Tax (1,000's)
Boston Edison	46	12,929	623	1.28	0	0.00	$1,069,285	94.58	4.06	$ 55,576
Carolina Power & Light	18	30,886	798	3.09	0	0.00	$1,647,183	100.00	0.00	$194,664
Central & South West	11	46,528	1,466	2.56	0	0.00	$2,812,634	97.98	2.02	$287,372
Central Hudson Gas & Electric	78	5,282	219	1.07	48	0.89	$ 473,738	86.92	13.08	$ 34,463
Central Illinois Light	87	4,110	184	–0.22	183	–0.35	$ 525,857	56.08	44.92	$ 37,797
Cincinnati Gas & Electric	40	14,997	607	1.22	366	0.04	$1,369,426	63.41	36.59	$121,096
Cleveland Electric Illuminating	37	16,637	713	0.23	0	0.00	$1,210,316	98.67	0.00	$207,600
Commonwealth Edison	4	61,217	2,991	0.66	0	0.00	$4,634,021	100.00	0.00	$694,598
Commonwealth Energy System	79	4,746	287	3.24	202	1.00	$ 619,866	57.60	39.74	$ 39,127
Consolidated Edison	16	31,689	2,774	0.54	1,018	0.07	$5,515,624	79.81	13.92	$536,832
Duke Power	8	54,151	1,357	2.64	0	0.00	$2,472,030	98.96	0.00	$368,677
Duquesne Light	51	10,990	556	–0.19	0	0.00	$ 800,345	99.08	0.00	$122,816
Eastern Utilities Associates	85	4,201	233	1.06	0	0.00	$ 302,450	96.55	0.00	$ 26,364
El Paso Electric	89	3,752	198	3.87	0	0.00	$ 302,443	99.64	0.00	$ 78,760
Empire District Electric	96	2,696	103	1.94	0	0.00	$ 116,079	99.54	0.00	$ 11,873
Houston Lighting & Power	7	55,226	1,274	5.39	0	0.00	$3,523,745	100.00	0.00	$291,294
Idaho Power	42	14,476	285	1.62	0	0.00	$ 376,144	100.00	0.00	$ 72,164
Illinois Power	41	14,811	530	0.62	382	–0.16	$1,278,269	61.85	38.15	$184,096
Indianapolis Power & Light	56	9,278	339	1.02	0	0.00	$ 427,542	94.17	0.00	$ 74,216
Interstate Power	90	3,751	156	0.57	45	0.69	$ 297,665	67.33	32.67	$ 20,321
Kansas Gas & Electric	66	7,261	239	1.54	0	0.00	$ 393,053	99.70	0.00	$ 92,027
Kansas Power & Light	64	7,706	283	[illegible]	986	640.65	$ 859,572	47.36	52.54	$ 75,293
Kentucky Utilities	52	10,605	373	1.59	0	0.00	$ 511,626	99.57	0.00	$ 63,740
Long Island Lighting	44	13,643	926	1.16	461	0.56	$1,767,851	80.32	19.68	$287,163
Louisville Gas & Electric	60	7,952	299	0.49	233	0.04	$ 637,684	63.67	36.16	$ 50,232
Montana Power	67	7,215	236	1.74	102	0.13	$ 488,776	42.30	29.81	$ 80,206
Nevada Power	76	5,687	214	4.31	0	0.00	$ 306,336	100.00	0.00	$ 31,016
New England Electric System	36	17,024	1,102	1.51	0	0.00	$1,373,876	96.96	0.00	$132,619
New York State Electric & Gas	49	12,286	684	1.19	130	0.29	$ 993,589	79.08	20.92	$133,214
Niagara Mohawk Power	14	34,732	1,392	0.87	433	0.46	$2,632,315	76.88	23.12	$270,300
Orange & Rockland Utilities	88	3,796	215	1.71	92	2.34	$ 526,045	71.15	28.55	$ 31,812
Otter Tail Power	92	3,597	122	0.73	0	0.00	$ 163,134	100.00	0.00	$ 17,179
Pacific Gas & Electric	5	60,012	3,594	1.36	2,949	1.17	$6,646,699	58.76	41.24	$628,143
Pacific Power & Light	26	24,404	650	–1.09	0	0.00	$1,598,400	54.97	0.00	$ 25,500
Pennsylvania Power & Light	27	23,057	1,026	1.24	0	0.00	$1,248,397	99.62	0.00	$210,173
Public Service of New Hampshire	71	6,351	302	2.91	0	0.00	$ 463,484	98.12	0.00	$118,362
Public Service of New Mexico	73	6,105	233	4.85	0	0.00	$ 397,474	98.61	0.00	$116,332
Public Service Electric & Gas	19	30,770	1,719	0.78	1,330	0.81	$3,962,932	64.86	35.14	$331,545
Puget Sound Power & Light	39	14,998	588	2.94	0	0.00	$ 518,511	100.00	0.00	$ 76,581
Rochester Gas & Electric	70	6,723	297	1.35	233	1.25	$ 756,061	61.32	36.55	$ 75,733
Southern Company	1	102,008	2,724	2.42	0	0.00	$5,418,043	99.13	0.00	$590,326
Southern Indiana Gas & Electric	82	4,538	106	1.47	64	1.24	$ 276,727	69.77	30.23	$ 24,778
Southwestern Public Service	45	13,588	342	9.60	0	0.00	$ 761,742	99.63	0.00	$ 90,023
Tampa Electric	53	10,527	365	4.27	0	0.00	$ 653,893	99.39	0.00	$ 70,314
Texas-New Mexico Power	77	5,521	182	4.39	0	0.00	$ 361,298	99.97	0.00	$ 11,348
Utah Power & Light	35	17,271	479	2.07	0	0.00	$ 854,898	99.85	0.00	$123,535
Washington Water Power	57	8,977	230	1.03	76	–0.16	$ 338,812	63.59	35.59	$ 55,888
Wisconsin Electric Power	33	17,777	822	0.40	221	1.47	$1,417,564	75.51	23.74	$134,870
Wisconsin Power & Light	62	7,730	311	1.27	106	1.32	$ 555,502	73.17	26.22	$ 49,624
Wisconsin Public Service	69	7,113	293	1.41	155	1.06	$ 629,891	61.79	38.21	$ 45,620

net incomes can find themselves in cash short positions and can pay dividends only through borrowing or through sales of assets. This problem is especially difficult for companies currently engaged in large construction programs, especially if nuclear plants are involved.

Median net income increase in 1983 was 7.9 percent and was posted by Dayton Power & Light. Last year the median net income gain was 11.1 percent. In 1981 it hit 22.6 percent.

Average earnings per share increased 8.1 percent in 1983, to $3.24 per share. In 1982, the average share earning was $3.00 and in 1981 was $2.82. The increase, 8.1 percent, was ahead of the 6.4 percent reported in 1982, but was below that posted in 1981, 11.9 percent.

TABLE III
THE TOP 10 NET INCOME AVAILABLE FOR COMMON STOCK

1	2	Commonwealth Edison	$694.6	37.2
2	1	Pacific Gas & Electric	628.1	–4.5
3	3	Southern California Edison	617.3	27.7
4	4	Southern Company	590.3	25.0
5	5	Consolidated Edison	536.8	18.5
6	6	Texas Utilities	461.5	7.7
7	8	American Electric Power	428.0	27.7
8	9	Middle South Utilities	378.1	21.7
9	7	Duke Power	368.7	9.7
10	10	Public Service Electric & Gas	331.5	14.7

The gain in the average earnings last year, $0.24, represents *one-half* the total dollar gain achieved from 1972 through 1982 ($0.48). The gain per average share amounted to only 19 percent over the entire 11-year period or 1.7 percent per year in current year dollars. Thus, the average-share performance in 1983 stands up well by comparison.

For 1983, 82 companies reported gains in per-share earnings from the previous year, while 17 utilities posted declines. This represents a small improvement from 1982, when 77 companies recorded gains and 22 declines.

For the 99 companies providing earnings data (Centel provided no earnings information), the median change was a 9.63 gain, compared with a 10.2 percent increase in 1982 and 10.4 percent in 1981.

As is typical when ranking performances based on relative improvement, those organizations coming off poor performances a year earlier tend to rise to the top of the list. The majority of those companies recording the highest per-share earnings improvements in 1983 tended to be at or near the bottom of the rankings a year previous. Six of the ten utilities of the top of this year's earnings gain ranking, and seven of the top 25, were among the 10 poorest performers in 1982. One company—General Public Utilities—ranked third again in 1983, the same as it ranked in 1982, reflecting the strong efforts of its management to rebuild the financial foundations of the company in the wake of the 1979 TMI-2 accident and the reluctance of the NRC to allow it to operate TMI-1. In total, six of this year's top 25 were in the top 25 last year, four moved up into the upper quarter from the second quarter a year ago and eight moved up from the third quarter.

Three companies reported earnings declines for the second straight year.

09735 1984293 W 3 2020
SUITE 800 COPY # 2
STATISTICAL REFERENCE IND
CONGRESSIONAL INFO SVC D
4520 EAST-WEST HWY STE 800
BETHESDA MD 20814

C8650-4A

Volume 62, Number 7
July 1984

Electric Light & Power

THE NEWS MAGAZINE OF ELECTRIC UTILITY MANAGEMENT AND TECHNOLOGY

Regulators mull scrutiny of EPRI

Did the institute capitulate?

TALLAHASSEE, FL—A subcommittee of the National Association of Regulatory Utility Commissioners, spurred by the research contract dispute between the state of New Jersey and the Electric Power Research Institute, will present the results of its EPRI oversight investigation at a meeting of regulators in San Diego July 23.

The subcommittee of NARUC's Committee on Electricity was formed after the New Jersey Board of Public Utilities became angered that EPRI had by-passed New Jersey and other American pump manufacturers in awarding a research contract to a foreign firm. The New Jersey commission subsequently escrowed a state utility's EPRI dues in an effort to extract a contract concession from EPRI.

With the recent acknowledgement from EPRI that it would "support" American pump research, the specific dispute now appears to be settled (see *EL&P*, May 1984, page 1; and June 1984, page 1).

However, broader issues have been raised. "We are seeking to review their whole procedure for awarding research contracts," Florida Public Service Commissioner Joseph Cresse said of the NARUC review subcommittee's effort. Cresse is head of the subcommittee.

Walking a fine line

At press time the investigation report was not complete, but Cresse said it would be similar to a conventional management audit report. It would, he said, state that in general EPRI does a good job of research contract review, but, nevertheless, the subcommittee had found areas where improvements could be made.

Although New Jersey regulatory commissioner Edward Hynes had called for the formation of a "national oversight board," with state representation to monitor EPRI spending, Commissioner Cresse sought to soften the tone of the request by suggesting that it be more of a continuing review committee.

"'Oversight' conveys the image that there is something wrong here and we have to straighten it out," Cresse said.

The Florida regulator stressed that it would be inappropriate for state regulatory commissions, which have to rule on electric company contributions to EPRI, to get involved "up front" in EPRI research contract review activities.

Nevertheless, Cresse does believe that regulators should establish an on-going process that would review such contracting procedures after the fact on a generic basis. "There is not much disagreement that regulators ought to be critiquing [research contracting] results...," he offered.

Continued on page 2

Hydro relicensing laws contemplated

The Tennessee Valley Authority's Fontana Dam in North Carolina is part of the 36 million kilowatts of installed hydroelectric facilities belonging to the federal government, according to statistics compiled by the Edison Electric Institute. Federal installations constitute about 46% of the 78 million kW installed nationally. Investor-owned utilities, as of 1982, operated facilities representing about 25 million kW, or about 32% of the total. Municipals, public power districts, and states operate, in the aggregate, about 17 million kW, or 22% of the total installed hydro power facilities. A vigorous dispute is currently underway in Congress between the public and private sectors of the electric utility industry regarding the relicensing of these increasingly valuable installations. Out of 377 hydrosite licenses held by 75 investor-owned electric utilities, 189 will be up for relicensing by December 31, 1993. The controversy focuses upon whether or not public power agencies should be shown a preference when competing with investor-owned utilities at relicensing time. A special feature exploring details of the dispute begins on page 11.

Alternatives to diversification

Cut rates, market energy to 'invest' excess cash

SCOTTSDALE, AZ—Eschewing diversification as a means of profiting from current healthy electric utility cash situations, a noted industry economist has recommended that companies consider cutting rates or marketing energy as "investment" vehicles.

THE COSTS OF MARKETING PROGRAMS

Number of years by which construction of a new plant is accelerated	Discounted cost to stockholders from acceleration (cents/kWh)
1	0.18
7	1.02
10	1.33
12	1.50

Source: National Economic Research Associates

"Some utilities find themselves in more agreeable cash and earnings positions than in the recent past, and are puzzled as to how to handle these unaccustomed riches," says Irwin M. Stelzer of the National Economic Research Associates.

"In their anxiety to keep these monies out of the grubby hands of shareholders and ratepayers, many have decided to diversify. While we have argued strenuously that regulatory agencies should not impede utility diversification, we remain uncertain about how well many utilities are endowed with the resources necessary to [conduct] a successful diversification program...."

Cut rates in self interest

Given the perceived likelihood that diversification will not provide a substantially profitable outlet for most utilities' cash, Stelzer suggested that instead of simply increasing dividends (one option that utilities may pursue), companies could cut rates.

Such a suggestion, he said, might appear strange coming from one who has long believed that for years consumers have been subsidized by utility owners, Stelzer said. "But it may well be the course of action most in the self-interest of utilities with excess capacity now and for the foreseeable future."

Example provided

In an attempt to validate his general remarks, he provided an example where an electric company is allowed a 16 percent return on equity but is actually earning 17 percent. Here, in the short run, a two percent rate cut would bring earnings down to about the allowed level.

However, electricity demand elasticities (or how demand moves with changing price) suggest that this two percent rate cut would increase sales

Continued on page 37

Acid rain harms nation's forests, says U.S. report

WASHINGTON, D.C.—There is good news and bad news in the second annual report from the U.S. government's Interagency Task Force on Acid Precipitation.

The group said acid rain doesn't seem to have any effect on most commonly planted crops. However, the task force said its research shows that acid precipitation may have a more damaging effect on forests than originally thought.

These were among the findings of the recently released National Acid Precipitation Assessment Program's (NAPAP) 1983 Annual Report to President Reagan and the Congress. The group was formed in 1980 and given a ten-year mandate to study the acid rain problem.

Headed by Executive Director Chris Bernabo, the group is jointly chaired by the National Oceanic and Atmospheric Administration, the Environmental Protection Agency and the Department of Agriculture.

During 1981 and 1982, most of the task force's efforts were in planning and organizing the program. In 1983, said the NAPAP, the emphasis was shifted toward producing results.

The report said, "Recent research and survey results have tended to reduce concern about acid deposition damage to crops, while increasing general concern about possible effects on forests."

Crops not harmed

Although farmers apply sulfur and nitrogen to their crops in much greater amounts than can be deposited by acid precipitation, the task force said the crops don't seem to be affected.

"The few relevant studies to date suggest the most commonly planted varieties of crops are not highly susceptible to acid deposition, although some cultivers (farmers) have shown reduced yield," concluded the task force.

The task force said that sulfates contribute about two-thirds of the acidity to precipitation in the Northeast U.S., while nitrates can contribute over half of the acidity in western areas of the country.

NAPAP research found that air pollutants such as ozone have a greater effect on most crops than acid precipitation.

Said the task force, "Although future research is required to increase the certainty of our conclusions, concern over crop losses has decreased substantially. For forests, the story is different."

Previous research on forest tree productivity indicated that forests were not expected to be threatened by acid rain, said the group.

Heightened concerns

"However," it reported, "observed declines in tree growth and forest dieback in areas with elevated pollution levels and high acid deposition, such

Continued on page 10

Foreign Power Briefs

- **Ontario Hydro** has decided to proceed with a retubing of the Pickering nuclear plant's units 1 and 2. The utility said the process will be complete by 1987. The Canadian Nuclear Association reports the retubing will cost about $720 million. Both units have been shut down for several months. Ontario Hydro originally planned to restart the units later this year, but utility Chairman Milan Nastich said that early replacement of the pressure tubes was practical and more prudent. The Zircaloy-2 pressure tubes in units 1 and 2 will be replaced by zirconium-niobium tubes (the type used in CANDU reactors), said the nuclear association. As a precaution, Ontario Hydro will shut down Pickering-3 for testing of selected pressure tubes.

- **The China National Coal Development Corp. (CNCDC)** of Beijing and Bechtel have formed a company to engineer and build projects in the People's Republic of China. The joint venture, China American International Engineering, does not have any projects currently underway. Bechtel said the company initially will be looking for coal-related work.

- **The People's Republic of China** has awarded a contract worth more than $5 million to the Power Engineering Group of Siemens AG to supply 25 high-voltage SF_6 circuit breakers for 525-kV and seven of the same for 245-kV. Siemens said the equipment will be used in a 300-km transmission line being constructed by the North China Power Administration from Datong to Beijing.

- **China** also has awarded a contract to Gibbs & Hill, Inc., and Quadrex Corporation for consulting services for the Guangdong nuclear power station. The plant will have two 900 MW pressurized water reactors and will be located in Guangdong Province in southern China. The Gibbs & Hill/Quadrex venture will furnish estimates of the major portion of the plant; assess the quality and completeness of major bid specifications; evaluate technical services; and consult and assist in supplier negotiations. The value of the contract was not disclosed.

- **Taiwan** says it will build its fourth nuclear power plant for a cost of $4.3 billion. Chen Lan-kuo, chairman of the Taiwan Power Company, said bids from companies in the U.S., Britain, France, West Germany, Canada and Japan would be invited for the 2,000 MW plant. It is scheduled for completion in 1994.

- **The U.S. Agency for International Development's,** mission to Pakistan has selected Gibbs & Hill, Inc., to provide technical assistance for the overall management and related functions for the expansion of the Guddu Thermal Power station near Karachi, Pakistan. The $300 million expansion involves the addition of a 450 MW combined-cycle plant. Gibbs & Hill says the expansion will be complete in early 1987.

- **The United Kingdom's** Department of Energy reports that 1983 was a "year of key significance in the exploitation of the hydrocarbon reserves of the UK Continental Shelf." Drilling activity was the highest since exploration began in 1964, said the Energy Department in its annual report. Total UK oil production in 1983 was 114.9 million metric tons (including natural gas liquids), compared with 103.2 million metric tons in 1982. The report said five offshore oil fields came onstream during the past year, bringing the total number in production to 25.

- **Brazil** and the U.S. have signed an agreement for a five-year program to develop underground coal gasification technology that can be applied to the Triunfo coal deposits. The U.S. will provide technical assistance.

In This Issue

Editorial 4

The public and private sectors of the electric utility industry have gone to Congress with their long-standing dispute over the issue of "preference" in the relicensing of hydroelectric facilities. A special report explores the subject. 11

Calendar 13

Right-of-way clearance costs have been trimmed at Philadelphia Electric with a new herbicide. T/D 19

William Derrickson takes charge of Seabrook construction at Public Service of New Hampshire. G 21

Fluidized bed boilers are being built in large, utility-scale projects. G .. 27

A fresh look at supercritical plant operations shows they're not doing so badly. G 32

New Products 39

New Literature 40

Readers' Service 43

Personnel 45

Advertisers' Literature 48

Regulatory Review 49

Management Methods 54

EL&P readers whose responsibilities include both Generation and Transmission/Distribution receive both technology sections. Other readers receive the technology section that applies to their respective area of responsibility. The Generation edition is indicated by a single dot (•) in the upper right corner of page 1; the T/D edition carries two dots (• •). All readers receive EL&P's industry news section.

TMI-1 ruling will be delayed again

WASHINGTON, D.C.—The long-awaited NRC ruling on the restart of the undamaged TMI-1 reactor will be delayed again.

In May, an Atomic Safety and Licensing Appeal Board said that unanswered questions remain concerning GPU Nuclear's management competence.

A three-member ASLB ruled in 1981 that GPU was fit to operate the unit, but the Appeal Board said in late May that additional hearings should be held.

NRC spokesman Robert Newlin said the ASLB Appeal Board has sent the case back to the original board for further hearings on the adequacy of the TMI-1 operator training program. Also, the Appeal Board said hearings should be reopened concerning TMI-1 leak rate falsification charges.

GPU Nuclear said the NRC has enough information to make a decision in the case without further delay.

Reacting to the appeal board ruling, the NRC commissioners met June 1 and voted 3 to 1, with one abstention, to ask all the parties involved to comment on the Appeal Board's action. Commissioner James Asselstine dissented, while outgoing Commissioner Victor Gilinsky abstained from the vote.

NRC Chairman Nunzio Palladino had said the Commission would make a restart decision by June 27. The Commission gave interested parties until June 15 to comment. But, intervenor Three Mile Island Alert asked for more time and the commission voted to extend the deadline for comments until July 6.

In a prepared statement, GPU Nuclear said, "We believe that the Commission has the information available to it now to permit it to make a supportable decision in this matter and respectfully urge that it act on that information."

GPU Nuclear said in its memo to the NRC that the matters remanded to the ASLB "have been the subject of extensive materials available to the Commission and its staff since the close of the hearing before the Licensing Board."

The ASLB Appeal Board said the present state of the record in several areas didn't permit it to make an ultimate judgement in the case, said NRC's Newlin.

GPU Nuclear said the NRC has more information available to it than the Appeal Board because the Appeal Board is confined only to the record of the ASLB hearings.

The utility noted that the NRC originally projected that the hearings would be completed in one year. They are now approaching their sixth year.

Grand Gulf's TDI diesel generators declared reliable

WASHINGTON, D.C.—After disassembling and inspecting a Transamerica Delaval, Inc. (TDI) emergency diesel generator at the Grand Gulf nuclear plant, Mississippi Power & Light said it could be declared reliable for the first cycle of the plant.

The Nuclear Regulatory Commission had ordered MP&L to reinspect one of the two Transamerica emergency diesel generators at the plant, because of questions concerning their reliability.

On August 12, 1983, the main crankshaft on one of three TDI emergency diesel generators at the Shoreham nuclear plant broke into two pieces during a load test.

After evaluating the failure at Shoreham, the NRC said it found information that questioned the reliability of all TDI diesels. So, in June, it ordered MP&L to disassemble and inspect the TDI diesel generator with the most hours of operation at the Grand Gulf plant.

Upon concluding a two-day inspection of the emergency diesel generator, the NRC said the "inspection has given confidence that the diesels are reliable and sufficient for the first cycle of operations."

The first cycle extends through the first fuel reloading, approximately 18-24 months.

Some minor damage

MP&L said that inspection of the diesel generator's turbocharger revealed that it had sustained some minor damage to some turbine blades, because two small bolts had sheared off. The utility said it would not have affected operation of the equipment.

Ed Beldowski, manager of public relations for TDI, said he didn't think the Grand Gulf inspection was really necessary, but added that it probably helped to allay concerns about the generators.

Regulators/EPRI . . . from page 1

"Regulators walk a fine line," he added, "analyzing the results of managerial decisions...We do not want to cross that line because if we do we lose our objectivity."

"I personally do not think regulators have any business directing the research efforts of EPRI," Cresse said.

Questioning porkbarrelling

Asked whether the recent EPRI/New Jersey BPU dispute raised the issue of state commissioners using utility rate cases for state porkbarrelling, Cresse responded, "Yes, that's always a concern."

He noted that if state commissions began to do this "the whole thing could catch fire."

Cresse termed it "a horrible situation" if at any time a state commission were able to require that all state research money given to EPRI be spent in that state.

But he made it clear that in a separate investigation NARUC would not look at individual regulatory bodies and how they make their decisions, but at whether "EPRI conducts its affairs in an appropriate manner and does not cave in to undue pressure" to grant research contracts.

He emphasized that EPRI must be free to get the best for its money regardless of where this happens to fall geographically—whether in a particular state, the U.S. or abroad.

"If NARUC thought EPRI was porkbarrelling its projects, that would be a concern," Cresse said. But he added that he did not know if it was a concern if one commission tried to secure EPRI funding for research in its state.

The determination of whether EPRI was coerced into granting a research contract will be issued separately from the subcommittee's oversight report, Cresse said. He promised to report on his findings at about the same time the subcommittee report on EPRI contracting procedures is released.

Transmission-Distribution Update

Canadian power imports to rise in next 10 years

ARLINGTON, VA—Canadian power imports to the Northeast will increase to 25,000-gigawatthours (gWh) in 1990 and 35,000-gWh in 1995, according to a new study.

Electricity imports from Canada to the northeastern part of the U.S. were 17,802-gWh in 1981.

Energy Ventures Analysis, Inc., a coal forecasting service, recently released results of a study on the impact of Canadian power imports on coal demand in the Northeast.

"Hydro Quebec and Ontario Hydro over-forecasted their demand growth and overbuilt new nuclear and hydro capacity," said Seth Schwartz, director of the study. "As a result, they have a tremendous surplus of low-cost power which they are marketing to oil-fired utilities in New York and New England. The only limitation on these sales is the need to build new transmission capacity."

In many cases, according to Schwartz, the contract sales (see table) to northeastern utilities understate the actual sales expected.

Maximum sales

The study found that maximum power sales under the Hydro Quebec contract are 24,000-gWh to New York and 6,000-gWh to New England. Schwartz said this boosts the maximum imports under the existing contracts to about 40,000-gWh.

He said this would be equal to about 20 percent of the total power demand in the Northeast and would exceed the region's coal-fired generation.

Hydro Quebec has proposed to increase its exports to New England from 690 MW to 2,000 MW by adding transmission capacity in the early 1990's.

Results from the study showed that the impact of power imports on the need to build new capacity has been dramatic. Five coal-fired plants totalling 3,158 MW have been cancelled over the last four years. Energy Ventures Analysis said electric utilities in the northeastern part of the country are forecasting a 1993 peak demand of 44 GW. Existing capacity is 50.6 GW, with 4.8 GW under construction.

High reserve margin

With the Canadian import capacity of 6.3 GW, the firm concludes the Northeast will have a 40 percent reserve margin in 1993. The forecasting service says this means that power imports have "effectively deferred any new coal-fired power plants until after the year 2000."

Robert Sansom, president of Energy Ventures, said, "Power imports have helped to delay most of the pending coal conversions in the Northeast as well. With cash flow problems caused by building five nuclear power plants, most of the utilities can't afford the investment to convert to coal.

"Imported power reduces the capacity factor that a converted unit would achieve, which impairs the economics of coal conversion," Sansom added. "Imports will also substantially decrease oil consumption in the Northeast, reducing the incentive to convert."

United Illuminating, Public Service of New Hampshire, Central Maine Power, Northeast Utilities, Long Island Lighting, Boston Edison, Consolidated Edison and Orange & Rockland are among the utilities that have delayed coal conversions, found the study.

"The increase in power imports which we expect from 1981 to 1995 is equal to seven million tons of new coal demand," said Schwartz. "Coal will not serve new growth in this market until the next century, because the Canadian surplus is too large to be worked off."

CONTRACTS FOR CANADIAN POWER IMPORTS TO NEW YORK AND NEW ENGLAND

Buyer	Seller	Contract Capacity (MW)	Contract Sales (GWh)	Begins	Expires
New York Power Authority	Hydro Quebec	–	7,000	1984	1987
			9,000	1987	1997
Vermont	Hydro Quebec	150	–	1985	1995
New England Power Pool	Hydro Quebec	690	3,000	1986	1997
Central Maine Power	New Brunswick	100	900	1983	1984
		150	1,300	1984	1995
Vermont	Ontario Hydro	252	–	1982	2002
Niagara-Mohawk	Ontario Hydro	400	3,160	1983	1992
Massachusetts Municipal Wholesale Electric	New Brunswick	100	–	1982	1990
Boston Edison	New Brunswick	100	–	1982	1995
Other	New Brunswick	30	–	1982	1990

Source: Energy Ventures Analysis, Inc.

Battelle study team to produce demand-side guidebooks

COLUMBUS, OH—Battelle's Columbus Laboratories said it is embarking on a "major project" designed to help electric utilities lower system costs and improve customer relations through the use of demand-side management.

The goal of the project is to develop a series of guidebooks for utilities to use in planning and implementing demand-side management programs.

Battelle said the project will be supported by a three-year, $1.6 million grant from the Electric Power Research Institute.

During the project, Battelle will attempt to develop practical guidelines, resource material, methods and software programs that utilities can use to analyze demand-side management programs.

Project leader David E. Jones said the focus will be on integrating the large amount of available information into a consistent form the electric industry can use.

Initial review

Initially, Jones said the team will review the demand-side management programs of utilities, compile an inventory of approaches and develop methods utilities can use to analyze customer acceptance and response to the programs.

Also, Battelle will devise methods to assess the impacts that demand-side management approaches have on load shapes and transmission and distribution systems.

As part of the project, a periodic newsletter, *Demand-Side Management*, will be published. Interested persons can receive the free newsletter by contacting: John C. Skeleton, Battelle's Columbus Division, 505 King Ave., Columbus, Ohio 43201-2693, telephone (614) 424-4616.

NJ development program expanded

NEWARK, NJ—Public Service Electric and Gas Company said that for the next seven years it will offer 7-15 percent lower rates to new or expanded businesses in nine New Jersey urban areas.

PSE&G Area Development General Manager John Maddocks said the BPU-approved Area Development Service is available to new or expanded commercial and industrial customers in Newark, Jersey City, Paterson, Elizabeth, Camden, Trenton, East Orange, Hoboken and Union City.

Maddocks said, "PSE&G works closely with the state of New Jersey in its economic development efforts. As a direct result of PSE&G's new service, I foresee a positive economic impact on these nine municipalitics, which offer tremendous opportunities for growth and expansion."

New customers

For new commercial or industrial customers, Maddocks said the minimum load must be 25-kW per month. For existing customers who expand, he said the minimum load is 50-kW.

Manitoba, U.S. sign largest hydropower supply contract

WINNIPEG, MANITOBA—The Western Area Power Administration has signed a letter of intent with Canada's Manitoba province to buy 1,275 MW of hydroelectric power each year for 35 years beginning in 1993, announced Manitoba Energy and Mines Minister Wilson Parasiuk.

Manitoba said that if the sale is finalized by Dec. 31, 1984, it would be the largest power supply contract ever between the U.S. and Canada.

The power will come, said the Manitoba Energy Authority (MEA), from a $3 billion hydro plant that will be built on the Nelson River.

New transmission facilities

MEA said new transmission facilities will have to be constructed from the proposed Limestone hydro station on the Nelson River to either Jamestown, ND or Watertown, SD. It has not yet been determined whether the facilities will be ac or dc, said MEA.

Since the Canadian National Energy Board, which must approve the sale, has a 25-year limit on export license terms, an application for a license extension will be filed after the first ten years of the agreement, said Minister Parasiuk. Either party has the right to terminate the agreement after 20 years by giving a ten year written notice and paying a termination fee.

The energy authority said the price of the electricity would be based on a percentage of the cost of Western Area Power's alternative energy sources. MEA said the sale price would never be less than a guaranteed minimum price to be negotiated between the parties.

The Canadian province also recently signed a preliminary agreement with Northern States Power to sell 500 MW a year for 12 years beginning in 1993.

Ensure development

Said Parasiuk, "Any successful sale to the Western Area Power Administration, in addition to the proposed sale to Northern States Power, will ensure a minimum of ten years of continuous hydro development in Manitoba with significant benefits for all Manitobans."

The MEA said the province has a developed generating capacity of 4,100 MW that is 90 percent hydroelectric. Manitoba's northern river systems have the potential for an additional 6,100 MW of hydropower, said the authority.

Western Area Power, an agency of the U.S. Department of Energy, is responsible for providing electricity to more than 500 municipalities, cooperatives and private utilities.

EEI transmission cable report out

WASHINGTON, D.C.—The Edison Electric Institute said its annual *Transmission Cable Operations* report is now available for $15 per copy.

The report describes installation and performance data on cables, joints and terminations operating at or above 69-kV. EEI estimates that the report covers between 75 percent and 95 percent of all EEI companies with such cable.

To order the publication, number 06-84-14, call EEI's order department at (202) 828-7551.

C8650-1A

Volume 62, Number 8
August 1984

09825 1957257 W 3 2027
JOSEPH MCNALLY
CONGRESSIONAL INFO SERVIC D
4520 EAST WEST HWY STE 800
BETHESDA MD 20814

Electric Light & Power

THE NEWS MAGAZINE OF ELECTRIC UTILITY MANAGEMENT AND TECHNOLOGY

TOP 100 REPORT

Best System Heat Rates

Company	Heat rate Btu/kWh
1. Duke Power	9762
2. Commonwealth Energy	9810
3. United Illuminating	9909
4. American Electric Power	9951
5. South Carolina Electric & Gas	9970

Best Unit Heat Rates

Unit	Heat rate Btu/kWh
1. Marshall 3	9021
2. Belews Creek 2	9031
3. Marshall 1	9033
4. Marshall 4	9125
5. Campbell 3	9135

Generating systems and unit thermal efficiencies are featured in this year's report on operations at the 100 largest investor-owned utilities, beginning on page 7.

Few problems solved by bankruptcy

WASHINGTON, D.C.—Not only is the unthinkable becoming thinkable, but the possibility of electric utility bankruptcy appears to be increasingly likely. However, according to the Congressional Research Service of the Library of Congress, shareholders, customers, and utilities are not to be much benefitted, if at all, by a troubled electric company or its owners pressing for bankruptcy.

"The bankruptcy of a utility solves little aside from providing protection from creditors, and may create a number of problems on its own," writes Alvin Kaufman, author of *Utility Bankruptcy: Thinking the Unthinkable.*

Kaufman, who is senior specialist in the CRS's division of Minerals and Regulatory Economics, was aided by research assistant Donald Dulchinos.

The report notes that there are no precise precedents for analyzing utility bankruptcies. Although in the past certain railroads have been forced into bankruptcy, these carriers acted under special statutory considerations, requiring the Secretary of Transportation and state and local officials to become part of the proceedings.

Similarly, the airlines that have been forced into bankruptcy proceedings were able,unlike regulated electric utilities, to set rates as required; additionally, they were free to enter or withdraw from markets as competition dictated.

Yet, CRS analysts believe that by employing certain simplifying assumptions, they could fruitfully analyze a hypothetical utility bankruptcy in order to provide a first-pass look at whether such an action actually affords relief from financial and/or economic problems. CRS researchers concluded that, in the main, it did not.

Reorganization or liquidation?

The CRS report recalls that bank-

Continued on page 29

Coalition of consumer groups challenges CEA ad campaign

WASHINGTON, D.C.—The multimillion dollar advertising campaign being conducted by the U.S. Committee for Energy Awareness is "grossly inaccurate and misleading," and ought not to be charged to the nation's electricity ratepayers, an alliance of environmental and consumer advocate groups has charged.

According to James J. MacKenzie, senior staff scientist at the Union of Concerned Scientists, the ads "present a decidedly lopsided and often distorted view of both the status of nuclear power and the availability of alternative means for meeting our national energy needs."

A spokesman for CEA denied the charge, declaring that the advertisements are accurate and truthful and that the Safe Energy Communication Council (SECC) has merely been set up to "harass" the committee and to generate controversial publicity.

SECC, which a spokeswoman says was established to pool resources to counter the thrust of CEA advertisements, consists of many mainstream and well-known environmental and consumer advocate groups. These include the Sierra Club, Environmental Action Foundation, Critical Mass Energy Project, Environmental Policy Center, Media Access Project, Solar Lobby, Friends of the Earth, and the Union of Concerned Scientists.

Fairness at issue

According to UCS's MacKenzie, "The results of reading and accepting their [CEA's] message at face value would be a serious misunderstanding of national energy issues generally and the problems affecting nuclear power specifically."

For example, MacKenzie asserts in a May 1984 critical review of CEA's printed ads that the committee's advocacy of building new coal and nuclear plants rests on debatable asssumptions. "Two of these," he said, "are that continued economic growth requires concomitant increases in electricity consumption and that renewable energy sources cannot make a significant contribution to national electricity supply for many years."

MacKenzie maintains that a number of studies contradict these conclusions and demonstrate that there are less costly and less risky means of meeting U.S. electricity needs in the future.

In his study, MacKenzie challenges what he sees as a rejection of alternative generating technologies in the CEA advertisements. He notes, for example, that photovoltaics are already beginning to be introduced for large-scale power production. Arco Solar, Inc. reportedly now is constructing a 16.5 megawatt facility to deliver power to Pacific Gas & Electric, with the first 5 MW already in place.

On a larger scale, the Sacramento Municipal Utility District (SMUD) has just dedicated the first phase of a 100-MW photovoltaic generating unit (see story, this issue, page 21).

"[F]ar from being only a glimmer in the eyes of renewable energy advocates, solar-powered electricity technology is being increasingly employed to meet utility needs," MacKenzie says. "Moreover, the downward cost trends are encouraging indicators that their use will continue to expand.

Conversely, DOE's forecast—cited in the ad—of about 180,000 megawatts of nuclear capacity by the turn of the century is totally unrealis-

Continued on page 3

EEI will begin funding TMI-2 cleanup activities by January 1

BOSTON—The first of six annual payments to the Three Mile Island cleanup trust fund will be made by the Edison Electric Institute by January 1, 1985. The EEI board of directors announced its decision to begin payment even though its preset condition of $100-million in individual utility pledges has not been reached.

EEI announced the board's decision during its 52nd annual convention here in mid-June.

The EEI board in January 1983 had said that payments from a $150-million voluntary contribution program to aid in cleanup of General Public Utilities' TMI-2 nuclear plant would not begin until it had received utility pledges totaling $100-million. The threshold was established to ensure that sufficient funds would be available before payments began.

To date, EEI companies have pledged about $81-million. Slowness in reaching the $100-million threshold was attributed to state utility commissions' concerns about funding the cleanup and lack of agreement as to how contributions to aid such activities should be treated for ratemaking purposes.

Because the funds are needed by GPU to maintain progress on the cleanup, the EEI board voted to waive the requirement.

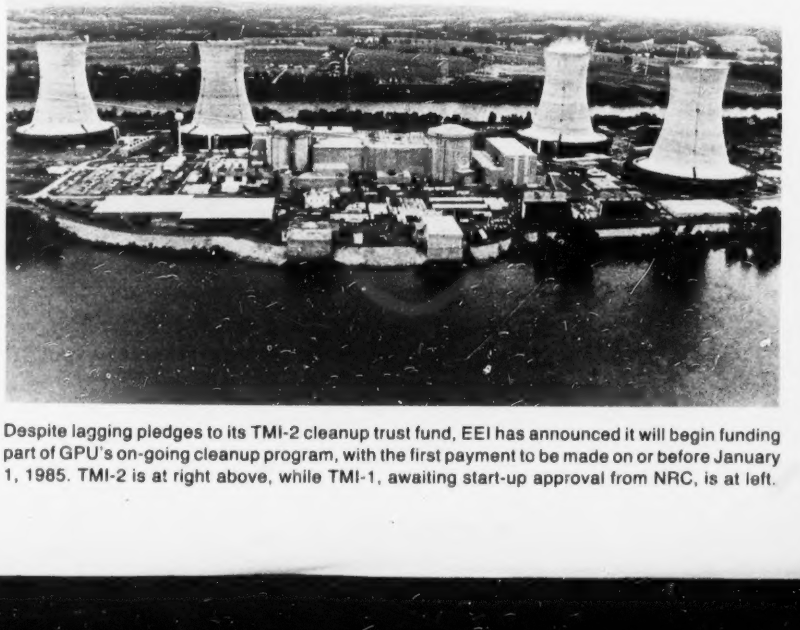
EEI President William McCollam, in announcing the board action, said "EEI remains firmly committed to this voluntary program, with a goal of raising $150-million toward the TMI cleanup."

A companion story, based on the presentation of Massachusetts Institute of Technology President Paul E. Gray, appears on page 34.

McCollam also reporterd to attendees that the general public's image of electric utilities and their services has improved overall since last year. Reporting on the April survey of nationwide public opinion conducted by Cambridge Reports, McCollam said "the good news seems to have gained on the bad news." The survey dealt with customer's opinions on the quality and reliability of their electric service, rates, the value of electricity, the industry's technological status and management quality and credibility. He also provided a summary of the Institute's activities during the previous year and outlined some new programs for the future.

Outgoing chairman Charles J. Dougherty predicted that a future shortage of electricity would entail high risks to national security and civil peace and pose "the most grevious danger for all to the nation." The so-

Continued on page 14



Despite lagging pledges to its TMI-2 cleanup trust fund, EEI has announced it will begin funding part of GPU's on-going cleanup program, with the first payment to be made on or before January 1, 1985. TMI-2 is at right above, while TMI-1, awaiting start-up approval from NRC, is at left.

Foreign Power Briefs

- **Officials of Switzerland's** Kernkraftwerk Leibstadt AG said their 942 MW Leibstadt boiling water reactor plant has begun low power testing operations. The plant is the first in Europe to use the BWR/6 design by General Electric's nuclear operations. GE said the Leibstadt plant is the second nuclear unit of its design to operate in Switzerland. The first was the 320 MW Muhleberg BWR near Berne.

- **Korea Electric Power Company** dedicated the country's largest fossil-fired power plant in June. The two-unit coal-fired, 575 MW Samchonpo station provides nine percent of the utility's 13,000 MW capacity. Samchonpo supplies electricity for the heavily industrialized area around Pusan.

- **Approximately 79 percent of Canadians** have a generally favorable attitude towards their electric utilities, reports a recent CROP Report on public attitudes. The figure rose from 74 percent last year. When asked about the quality of electric service, 82 percent of the respondents said it was excellent or good. That was a 13 point plummet from the 90 plus level obtained in surveys from 1978 through 1983. The Canadian Electrical Association said the drop can be attributed to low ratings received in Montreal. Storms last winter resulted in blackouts that affected sections of the city.

- **China** said it has discovered more than 400 million tons of coal reserves in the southern Guangxi Zhuang autonomous region, which borders Vietnam. The official New China News Agency said the reserves were the largest found yet. The news agency said the coal will help to alleviate the region's reliance on coal shipped from mines north of the Yangtze River.

- **The Organization for Economic Cooperation and Development** (OECD) said the amount of nuclear electricity produced by the world's most industrialized countries rose approximately 12 percent last year to 806 billion kilowatt-hours. Nuclear electricity output grew eight percent in 1982. OECD said nuclear power production rose sharply last year in Canada, Belgium, France, Japan and the United States. France relies on nuclear power the most. OECD said that almost 49 percent of France's electricity comes from nuclear plants, up from 39 percent in 1982. Nuclear power provided 12.7 percent of the U.S.'s electricity production in 1983.

- **International Energy Agency** member countries are predicting an increase in coal demand to 1000 Mtoe in 1990 and 1350 Mtoe in 2000. Solid fuel use in IEA countries was approximately 850 Mtoe in 1980 and 1982. In a new report entitled *Coal Prospects and Policies in IEA Countries*, IEA said a major increase in coal production and use over the next two decades is essential to strengthen the energy security of IEA countries and to ensure that energy does not again become a constraint on economic growth.

- **Rolls Royce Limited** and the General Electric Company of the Ukraine (GEC) said they have formed a joint venture to supply gas turbine driven power generation equipment above 10 MW. GEC Rolls-Royce (Power Generation) Limited said it will operate out of Whetstone, England. A spokesman said the new company brings together the gas turbine and electrical engineering expertise of Rolls-Royce and GEC.

- **Poland** exported more than 23 million metric tons of coal this year, said P.A.P., the official Polish news agency. If the level of exports continue, P.A.P. says it will be a record year for coal sales abroad.

In This Issue

Editorial 4
Operating data from the top 100 investor-owned electric utilities is reviewed for the year 1983.............................. 7
Accurate facilities planning requires careful population projection, reports Gilbert/Commonwealth. **T/D** 17
Calendar.............................. 19
Utilities are trying to turn around the five-year decline in nuclear plant capacity factors with aggressive programs aimed at improving plant operations. **G** .. 25
S. David Freeman talks about his controversial seven-year directorship at the Tennessee Valley Authority. A special interview.............................. 31
Readers' Service 45
New Products 51
New Literature.............................. 54
Advertisers' Literature.............................. 56
Personnel 57
Regulatory Review 58
Management Methods 62

EL&P readers whose responsibilities include both Generation and Transmission/Distribution receive both technology sections. Other readers receive the technology section that applies to their respective area of responsibility. The Generation edition is indicated by a single dot (•) in the upper right corner of page 1, the T/D edition carries two dots (••). All readers receive EL&P's industry news section.

Acid rain jeopardizes U.S. resources, says OTA

COSTS OF REDUCING SO_2 EMISSIONS IN THE EASTERN 31 STATES (EXCLUDES COSTS TO MEET CURRENT SIPS OR TO OFFSET FUTURE EMISSIONS GROWTH; ALL COSTS IN 1982 DOLLARS)

Emissions reduction (million tons SO_2)	If utility is required to choose most cost-effective control (Total cost) (billions of dollars/yr)	If utility is required to choose wet scrubbers[a] (Total cost) (billions of dollars)
4.6	$0.6-0.9	1.4
6.2	1.1-1.5	2.0
8.0	1.8-2.3	3.1
9.3	2.6-3.4	4.0
10.3	3.2-4.1	4.8
11.4	4.2-5.0	

(a) Assumes statewide emissions reductions are from those utility plants that can install scrubbers most cost affectively. Old and small units are exempt from the requirement to install scrubbers, but equivalent emissions reductions are obtained from other plants within each state.

Source: Office of Technology Assessment

WASHINGTON, D.C.—Our nation's resources are being endangered by acid rain, ozone and fine particles in the air, says a new report by the Congressional Office of Technology Assessment (OTA).

These air pollutants have harmed lakes and streams, lowered crop yields, damaged manmade materials, decreased visibility and may be threatening forests and human health, according to the report.

However, OTA said that controlling the pollutants will be extremely costly. OTA recommends that both sulfur dioxide and nitrogen oxides be considered for a nationwide control program.

If a modest sulfur dioxide control program—eliminating two to five million tons a year—were enacted, OTA said it would cost about $1 billion per year. A larger program to eliminate eight to 10 million tons a year would cost between $3 and $6 billion per year, said OTA.

The acid rain report was requested by Sen. Robert Stafford (R.VT), chairman of the Senate committee on environment and public works, Rep. John Dingell (D.MI), chairman of the committee on energy and commerce and Rep. Henry Waxman (D.CA), chairman of the subcommittee on health and environment of the committee on energy and commerce.

OTA is the nonpartisan research agency of Congress.

Source of problem

During 1980, approximately 27 million tons of sulfur dioxide and 21 million tons of nitrogen oxides were emitted in the nation. OTA said almost 80 percent of the sulfur dioxide and 65 percent of the nitrogen oxides come from the 31 states bordering on or east of the Mississippi River.

If energy-use patterns and current laws do not change, the congressional agency said both sulfur and nitrogen emissions will remain high for at least the next half-century—long enough to be significant to natural ecosystems.

Scientific uncertainties about acid rain continue to cloud the problem, said OTA. It said that additional scientific research will not provide an unambiguous answer in the near future, nor will it ever resolve value conflicts.

Time to act

Sen. Stafford said after reading the report that "the time to act is now, because to wait for the small chance that evidence will reverse course is to gamble America's heritage on an increasingly improbable outcome."

Rep. Dingell said the study shows there are still considerable uncertainties about the acid rain problem. However, the congressman said he is not opposed to reasonable and fair legislation that would deal with the problem in a national way.

Inaction risks damage

"This new report offers an invaluable source of information, indicating once more that continued inaction risks overwhelming damage to our nation's lakes and forests," said Rep. Waxman.

OTA said acid rain is high in most of the states east of the Mississippi, as far south as Tennessee and North Carolina. It estimates that there are about 3,000 lakes and 20,000 miles of streams, scattered throughout the eastern U.S., that are extremely vulnerable to acid rain or already are acidic.

Single greatest factor

Sulfate particles in the air are the single greatest factor in reducing the visibility in the eastern U.S., causing about half of the decrease in visibility annually and even more during the summer, said OTA.

Although research on the effects of airborne sulfates and other fine particles on human health are inconclusive, OTA said these pollutants may increase mortality rates.

The agency also said that ozone is causing about a 6 to 7 percent overall loss of U.S. agricultural productivity. Ozone is produced when nitrogen oxides interact with hydrocarbons.

If ozone were reduced to natural background levels, OTA said wheat and corn yields would increase by a few percent, soybean yields would rise 10 percent and peanut yields would go up by one fourth.

Tree growth drops

Another problem the report addressed is the declining tree productivity in the eastern part of the country and Europe. OTA said that over the past 20 to 30 years, productivity of several species of trees has declined in areas of high air pollution.

OTA said it believes that if a large emissions control program (8-10 million tons) were enacted, many sensitive aquatic resources would be protected. "Risk of damage to forests, agriculture, materials and health would likewise be reduced and visibility would improve," said OTA.

Electricity consumers would pay the most for a large cleanup, because approximately three-fourths of the sulfur dioxide emitted in the eastern U.S. comes from coal-fired plants. OTA estimates that if such a program were implemented, electricity rates would increase an average of two to five percent—rising as high as 10 to 15 percent in a few midwestern states.

NARUC's utility performance study scrutinized for usefulness

Don Minner
Assistant Editor

WASHINGTON, D.C.—Regulators and utility officials are closely examining a comprehensive study of electric utility financial and operating performance made by the National Association of Regulatory Utility Commissioners (NARUC) to determine its usefulness and value.

Author Michael Foley, NARUC director of financial analysis, said the report is an attempt to develop an objective means by which utilities can be compared over time to others in the industry.

The report compares financial performance, electricity price trends and operating performance of 130 major electric companies from 1972-1981.

Southern Indiana Gas & Electric was cited for the strongest financial performance over the 10-year period, while Western Massachusetts Electric had the weakest financial performance. Montana Power Company had the lowest residential rate increase from 1972-81, while the study said Hawaiian Electric Company had the highest rate increases.

The study found that Pennsylvania Power & Light had the highest improvement in productivity over the ten years, while Louisiana Power & Light had the lowest.

"Utilities are generally not wild about being ranked," said Foley. "A utility is always concerned when someone says "company A" is better than "company B"."

Edison Electric Institute Senior Vice President Douglas Bauer said, "Inevitably, anyone trying to rank utilities has to make some kind of judgement that will preordain the results." He said that it is unfortunate that people will probably leap to conclusions on the rankings and not take time to read through the report.

Bauer said intercompany comparisons are "a hazardous process at best."

Most people in the industry are wondering how the report will be viewed and used by regulators.

"I think it's (the study) a useful product," said Iowa Commerce Commission Chairman Andrew Varley, "perhaps not directly to commissioners, but definitely to the investment community. I think it's helpful to see where the utilities in your jurisdiction fit in with others."

Varley said he doesn't see how a regulator can use the report to help make a specific decision in a rate case. He said he feels the report will be useful in a general sense.

"If you find that one of your utilities is at the bottom of the range, you'd want to spend some time to see what's wrong," explained Varley. He said the NARUC study will help spot trends and trouble spots.

Both Foley and Varley said utilities at both ends of the rankings will probably get attention from regulators.

Foley says that a broad comparison is helpful. "I think it's important for everyone to get a handle on where the company stands in respect to others," he said.

Response to the report has generally been good. According to Foley, utilities, regulators and consultants are "scooping up copies."

The most common criticism of the report is its timeliness. Since so much has happened to the economy and the utility industry in the past two years, there is concern over the value of the statistics.

"If there is one fault of the report," said Varley, "it is the age of the information."

Foley said that many of the comments he has received have to do with the report's timeliness. Foley said that he worked for a year on building a data base and putting together the report. Now that it's finished, he said that he would like to get another report out this year that will be updated through 1983.

"I'm very willing to do the project on an annual basis," Foley said.

It seems likely he will get the opportunity. Varley, who serves as the chairman of NARUC's electricity committee, said he will invite Foley to make a report on the study at the next committee meeting. Varley said he also plans to recommend that it be done annually.

"I think it makes for a very interesting report," said the Iowa regulator.

Bauer said that EEI is still studying the report and will comment on it at a later date.

Foley said that officials from a number of utilities have told him that they often do intercompany comparisons. He said most of the callers are interested in the techniques used in the study. Varley said the Iowa Commerce Commission also is working on a similar type of study.

Varley said the report is the first time NARUC has been able to get a comprehensive study done without spending a large amount of money.

To rank the companies in order of performance, NARUC used 10 ratios. They included current ratio, AFUDC/net income, pre-tax interest coverage ratio, post-tax interest coverage ratio, cash coverage of common dividends, long-term debt ratio, interest and preferred dividend coverage, electric operating ratio, return on equity and return on investment.

In a statement accompanying the report, Foley said the ratios were picked to weight "the model in such a manner as to increase its sensitivity toward the measurement of the firms' cash position." Foley said this reflects his view that the most appropriate measures of electric utility financial position are those which emphasize cash flow.

He based the rankings on a financial performance percentage derived by taking the total number of "financial quality points" earned by the utility during the ten years as a percentage of 500 points. A utility could earn a total of 50 points each year.

Productivity was ranked by using a technique known as Total Factor Productivity (TFP), said Foley. He explained that TFP measures changes in the utility's output (kilowatthours) versus the inputs (labor, fuel, capital, etc.) used to produce power.

The NARUC report found that the average electric utility improved its TFP value by roughly one percent per year over the ten-year period. Of the 117 electric companies analyzed for the productivity section of the report NARUC said 83 had positive TFP changes and 34 utilities had negative changes.

Copies of the 229-page report can be obtained by sending $25 to NARUC, P.O. Box 684, Washington, D.C. 20044.

STRONGEST FINANCIAL PERFORMANCE (1972-1981)

Rank	Utility	Financial Performance Percentage
1	Southern Indiana Gas & Electric Co.	88.60%
2	Texas Electric Service Co.	86.80%
3	Wisconsin Electric Power Co.	86.00%
4	Texas Power & Light Co.	85.80%
5	West Texas Utilities Co.	84.40%

WEAKEST FINANCIAL PERFORMANCE (1972-1981)

Rank	Utility	Financial Performance Percentage
130	Western Massachusetts Electric Co.	31.60%
129	Alabama Power Co.	32.20%
128	Boston Edison Co.	32.80%
127	Detroit Edison Co.	32.80%
126	Kingsport Power Co.	37.20%

Source: National Association of Regulatory Commissioners

CEA ad campaign . . . from page 1

tic, ignores recent trends in cancellations, and indicates the agency's (and CEA's) overall bias toward large central, and preferably nuclear, power plants."

SECC petitions regulators

As part of its current campaign to thwart the advertising efforts of CEA, the Safe Energy Communication Council has petitioned each state regulatory commission to "examine closely any advertising costs submitted as operating expenses by electric utilties in rate proceedings."

The SECC request comes at a time when the National Association of Regulatory Utility Commissioners is conducting its own inquiry into how funds contributed by electric companies to various industry organizations are collected, spent, and recovered (see *EL&P*, February 1984, page 1; April 1984, page 1; and June 1984, page 2).

Arguing that the CEA campaign is intended to influence the public toward the side of nuclear power, the SECC letter to regulators encourages state commissioners to identify and disallow all expenses for CEA's and similar "self-serving campaigns."

The exact degree to which electric companies are expensing their contributions to CEA and other similar organizations has been difficult to determine. This is because individual regulatory jurisdications have different rules governing such expenditures and manifest varying levels of scrutiny over such matters.

For its part, CEA is unsure of how much is being charged to ratepayers, although it believes not many utilities currently are taking CEA contributions above the line.

"It's our impression that not many assign support of CEA to ratepayers," CEA director of public relations Carl Goldstein told *EL&P* in a telephone interview.

He said that out of a CEA membership of approximately 150 organizations, about half were electric utilities. Other members include suppliers, vendors, and consultants. According to Goldstein, however, electric utilities provide CEA with a disproportionately higher percentage of the committee's funds than its membership ratio suggests. Exact figures on this were unavailable.

CEA ads: 'truthful and accurate'

Contrary to the allegation of SECC, the Committee for Energy Awareness sees itself as providing a balanced view of the electricity supply and demand situation and of nuclear power.

"We are confident that what we are saying is truthful, and I know it is accurate . . . ," Goldstein maintains. Noting that the current annual CEA budget of about $20 million is only about 1/50th of 1 percent of annual electric utility industry revenues, the CEA spokesman says the money goes "to provide a more rational climate" for weighing the issues of electricity demand and supply and thus correspondingly serves the public.

"We firmly believe that the money we are spending is in the interest of ratepayers and the U.S. public at large," Goldstein says.

In support of its declaration that what it prints and broadcasts is accurate, CEA's Goldstein notes that the three U.S. television networks require extensive documentation on the veracity of ads submitted for broadcast before they will air them. This is a rigorous and time-consuming process, Goldstein says, explaining that the networks do this in order that they not become excessively vulnerable to challenges, under the so-called Fairness Doctrine, by those who oppose the ads the networks accept for broadcast.

Seeking free air time under this doctrine, the SECC has challenged CEA commercials on all three networks but has been rebuffed, Goldstein says. "This is another indication," he offers, "that we are not playing fast and loose with the facts."

SECC spokeswoman Janet Bearden concedes that the networks so far have declined to provide free air time to the council in response to the nationally broadcast "Annie ad" CEA currently is running. The ad is so called because it draws from the broadway musical *Annie*.

But Bearden is quick to add that the final word is not in on SECC's free air time petition under the Fairness Doctrine and that there still are discussions going on between SECC and the networks. Noting that the networks, and ultimately the Federal Communications Commission, make the determinations on whether the CEA ads are sufficiently controversial to warrent the granting of air time for opposing views, Bearden says, "Absent an express FCC ruling, neither CEA nor the networks can properly claim the ads do not present controversial [material] of public importance."

"It is fair to say the match is not over," she adds.

Bearden also reports that while its challenge to CEA's high-cost network ad is still unresolved, SECC has been successful at local broadcast levels securing free air time in response to CEA ads. She estimates that to date this has amounted to about $280,000 in the aggregate.

Finally, CEA sees the SECC challenges to its media campaign as not, in fact, questioning the committee's truthfulness so much as disagreeing with CEA's vision of the future. The argument is, therefore, more philosophical than factual, CEA's Goldstein maintains.

The Top 100 electric utilities' 1983 operating performance

Robert Smock
Managing Editor

Peak demands soared upward at most of the 100 largest investor-owned electric utilities for the year 1983 due to the combination of a midwestern heat wave and economic recovery during the second half.

Indications of a resumption of strong demand growth stand out in this year's annual analysis of operating data taken from the 1983 Uniform Statistical reports of the top 100 IOUs. Raw data for each company is shown in the large tables on the next four pages and summaries for the top 100 as a whole are shown in the smaller tables.

The overall gain in peak demand of 4.2 percent is one of the largest in the past 10 years, exceeded only by the 5.4 percent of searingly hot 1980 and the 5.9 percent recorded in 1977, another year of economic recovery. The 1983 gain comes after a 1.8 percent decline in 1982, the first time that happened since *EL&P* began tracking the performance of the 100 largest investor-owned utilities.

Last year a whopping 82 utilities in the top 100 showed gains in peak demand, the same as in 1980. During the worst slump year, 1982, only 42 companies logged gains. The influence of the economic recovery on peaks can be seen in the list of the companies with the largest gains. Of the 14 companies with double-digit increases in 1983, 10 were from the industrial midwestern states:

- Southern Indiana Gas & Electric...+30.3 percent,
- Iowa Public Service...+15.7 percent,
- Southern Company...+15.0 percent,
- Montana Power...+13.5 percent,
- Louisville Gas & Electric...+13.4 percent,
- Portland General Electric...+13.3 percent,
- Wisconsin Power & Light...+12.1 percent,
- Cincinnati Gas & Electric...+12.0 percent,
- Wisconsin Electric Power...+11.3 percent,
- Commonwealth Edison...+11.1 percent,
- Detroit Edison...+10.5 percent,
- Puget Sound Power & Lt...+10.2 percent,
- Iowa Resources...+10.2 percent,
- Madison Gas & Electric...+10.1 percent,
- Cleveland Electric Illuminating...+10.1 percent.

The effect of the summer heat wave can be seen in the shifts from winter- to summer-peaking. In 1982 there were 32 winter-peakers. Last year there were only 19.

The overall 4.2 percent gain in peak was larger than the increase in energy demand during 1983, 2.2 percent for the top 100, because the economic recovery did not begin until the third quarter of '83. That was in time to push up summer peaks but only barely in time to cancel out the first-half declines in energy demand.

Evidence of the late-developing recovery can also be seen in the arithmetic average of company load factors which only increased slightly, to 57.7 percent. Load factor had dropped sharply in 1982, to 57.5 percent, from 1980 and 1981's 58.6 percent (which was down substantially from 1979's 60.0 percent.)

The strongly continuing economic recovery and signs of another hot summer indicate that 1984 might also show some large gains in electricity demand figures.

The fuel consumption data show a 3.9 percent gain in coal, driven by the 2.2 percent rise in energy demand, with consumption of oil and gas relatively flat. The oil consumption figure indicates that the rapid reduction in oil use over the past five years may be ended, and may even reverse.

Since 1978 the top 100 has cut oil consumption in half, with reductions of 18 percent in 1979 and 1980, 12 percent in 1981 and a whopping 31 percent in 1982. With a high probability of strong electricity demand for 1984 as a whole, and with the possibility of a coal strike looming in October, the oil consumption total could do an about-face. It is also interesting to note that the price of oil has dropped substantially over the past three years, in contrast to the price of gas which has risen sharply.

Many major oil consumers (more than one million barrels a year) continue to show large reductions from the previous year. The consumption-reduction leaders:

- San Diego Gas & Electric...-30 percent to 4.4 million barrels in 1983,
- Southern California Edison...-23 percent to 3.4 million,
- Tampa Electric...-21 percent to 2.4 million,
- Commonwealth Energy...-20 percent to 5.5 million,
- Orange & Rockland...-20 percent to 2.3 million,
- Commonwealth Edison...-20 percent to 5.8 million,
- Pacific Gas & Electric...-20 percent to 1.9 million,
- Virginia Electric & Power...-19 percent to 3.1 million,
- Florida Power...-14 percent to 9.2 million,
- Niagara Mohawk...-13 percent to 7.2 million,
- Eastern Utilities Associates...-11 percent to 3.4 million,
- Boston Edison...-10 percent to 10.4 million.

In the past few years this list has prominently featured utilities that converted oil-burning capacity to coal. This year the only large-scale converters on the list are VEPCO and Florida Power. The presence of the three big California utilities indicates 1983 was a good year for interchange of hydro electric energy.

TABLE 1
FOSSIL FUEL CONSUMPTION

	1982	Change	1983	Change
Coal (million tons)	461	–1.7%	479	+3.9%
Oil (million bbl)	227	–30.5%	228	+0.4%
Gas (billion cu ft)	2638	–16.3%	2586	–2.0%

TABLE 2
PEAK DEMAND AND RESERVE MARGINS

	1982	Change	1983	Change
Seasonal peak (MW)	363,164	–1.8%	378,465	+4.2%
Total system capability (MW)	466,943	+0.5%	474,238	+1.6%
System reserve margin	28.6%		25.3%	
Total owned capability (MW)	439,419	+1.5%	443,370	+0.9%
Owned reserve margin	21.0%		17.1%	
Average load factor	57.5		57.7	

On the other hand, there was an increase of oil consumption by utilities in the northeastern industrial states most strongly affected by the economic recovery. The list of leaders in increased oil consumption (among those consuming more than one million barrels a year):

- Texas Utilities...+215 percent to 2.2 million barrels,
- Philadelphia Electric...+103 percent to 8.7 million barrels,
- Pennsylvania Power & Light...+73 percent to 9.8 million barrels,
- Potomac Electric Power...+43 percent to 3.3 million barrels,
- Baltimore Gas & Electric...+24 percent to 3.1 million barrels,
- Central Hudson Gas & Electric...+20 percent to 6.4 million,
- General Public Utilities...+12 percent to 1.2 million,
- Atlantic City Electric...+10 percent to 2.3 million,
- Northeast Utilities..+10 percent to 11.7 million barrels.

If these utilities are burning more oil in convertible capacity, pressure could grow, as it did in the mid 70's, to convert those plants back to coal. Oil consumption has been dropping for five years, but if it turns strongly upward in 1984 to help fuel the economic recovery, concern over oil consumption and pressure to reduce it from the government might reappear.

The top 100 fuel consumption data also show a definite end to the "gas bubble" practices of the late 70s and early 80s. The U.S. Dept. of Energy encouraged utilities to reduce oil consumption by burning natural gas in plants that could convert, and the federal officials made the conversion easy by diverting gas to those utilities. As a result, gas use climbed 12 percent in 1979 and 4 percent in 1980 while oil use plummeted 18 percent each year.

However, rising gas prices choked off the trend. The top 100 reduced gas use 16 percent in 1982 and another 2 percent last year. Consumption by the largest gas users:

- Houston Lighting & Power...-16 percent to 360 billion cubic ft,
- Texas Utilities...+2 percent to 312 billion,
- Central & Southwest...-9 percent to 280 billion,
- Gulf States...-6 percent to 233 billion,
- Middle South...-20 percent to 233 billion,
- Southern California Edison...-16 percent to 215 billion,
- Pacific Gas & Electric...-15 percent to 170 billion,
- Oklahoma Gas & Electric...+6 percent to 140 billion,
- Florida Power & Light...+3 percent to 113 billion.

Coal consumption showed a 3.9 percent gain in 1983. The gain came out of stockpiles, as coal industry production declined substantially in 1983. Utilities apparently decided to cope with the second-half surge in energy demand in a conservative way by reducing coal inventories, rather than increasing supply contracts, according to national data on coal consumption. That trend appears to have halted, with coal companies shipping at a furious rate in 1984 as utilities simultaneously try to meet the 8 percent growth in first-half 1984 energy demand and restore stocks to a strike hedge level by October.

Utilities with the largest gains in 1983 coal consumption (among those consuming more than 3 million tons a year):

- Florida Power...+74 percent to

HEAT RATES AND FUEL CONSUMPTION

Company	Rank	Heat Rate (Btu/kWh)	Up or Down	Fuel Consumption Coal (1000 tons)	Fuel Consumption Oil (1000 bbl)	Fuel Consumption Gas (1000 MCF)	Percent Change In Coal	Percent Change In Oil	Percent Change In Gas
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Cincinnati Gas & Electric	6	10,009	D	7,101	769	112	+3	+13	−24
Detroit Edison	7	10,040	D	13,666	797	11,450	0	−56	+41
Consumers Power	8	10,054	D	5,933	255	228	+13	−18	−86
Dayton Power & Light	9	10,063	D	4,401	11	73	−9	−93	−75
Florida Power	10	10,082	D	3,768	9,195	6,808	+74	−14	−44
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Illinois Power	16	10,181	D	7,423	170	572	+9	+70	+271
Boston Edison	17	10,217	U	0	10,355	15,262	0	−10	+94
New England Electric System	18	10,224	U	2,772	7,932	3,079	−1	−9	+277
Eastern Utilities Associates	19	10,232	U	262	3,445	0	−	−11	0
Houston Lighting & Power	20	10,263	U	8,531	227	360,030	+36	−60	−16
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Florida Power & Light	26	10,372	D	0	34,696	112,782	0	+7	+3
Central & South West	27	10,380	U	11,513	517	279,961	+10	+92	−9
Hawaiian Electric	28	10,410	D	0	10,541	0	0	+2	0
Long Island Lighting	29	10,426	U	0	15,494	NA	−	+1	NA
Niagara Mohawk Power	30	10,433	U	3,191	7,230	19,689	−1	−13	−6
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Louisville Gas & Electric	36	10,474	D	3,733	1	344	+8	0	+30
Carolina Power & Light	37	10,494	U	9,827	64	2,209	+3	−16	−
San Diego Gas & Electric	38	10,495	U	0	4,430	37,597	0	−30	+5
Indianapolis Power & Light	39	10,512	U	5,419	50	0	+10	+4	0
New York State Electric & Gas	40	10,552	D	4,667	1	0	−3	−97	0
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Central Louisiana Electric	46	10,605	U	609	12	32,707	+15	−75	−24
Delmarva Power & Light	47	10,634	D	2,996	3,219	4,189	+50	−6	+3
Duquesne Light	48	10,635	D	4,205	99	0	−13	−8	0
Savannah Electric & Power	49	10,642	D	788	73	1,073	+8	−30	−23
Northeast Utilities	50	10,650	D	374	11,676	2,365	−7	+10	−29
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Rochester Gas & Electric	56	10,746	D	833	644	169	+4	+6	−84
Virginia Electric & Power	57	10,761	D	7,387	2,573	3,051	+7	−19	+20
Southern Indiana Gas & Electric	58	10,770	D	1,984	1	374	+9	−93	+225
General Public Utilities	59	10,782	D	7,404	1,172	25,850	+3	+12	+30
Baltimore Gas & Electric	60	10,795	U	2,301	3,133	1,427	+23	+24	+132
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Arizona Public Service	66	10,870	U	7,326	161	8,401	−1	+10	−19
Utah Power & Light	66	10,870	D	6,886	73	1,329	−4	+22	−56
Kansas City Power & Light	68	10,874	D	5,204	131	1,381	−1	+9	−46
Empire District Electric	69	10,887	D	1,135	19	491	+4	+90	+241
Wisconsin Public Service	70	10,902	D	3,003	338	220	+15	+745	+30
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Wisconsin Electric Power	76	10,993	D	5,642	166	1,742	+12	+1	−45
Central Vermont Public Service	77	10,996	D	0	45	0	0	+25	0
Texas Utilities	78	10,997	D	29,350	2,186	311,847	−2	+215	+2
Iowa Resources	79	11,064	D	2,035	26	19	+10	+37	−92
Commonwealth Edison	80	11,076	D	16,913	5,760	7,401	+8	−20	+22
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Portland General Electric	86	11,194	D	380	4	1	−27	+300	−97
Iowa-Illinois Gas & Electric	87	11,219	U	1,849	13	1,101	+9	−28	+25
Consolidated Edison	88	11,241	D	0	22,353	67,442	0	+5	−8
Interstate Power	89	11,248	D	2,111	25	1,122	+6	−7	+29
Public Service of New Mexico	90	11,296	NC	4,597	13	640	+27	−82	−82
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Kansas Power & Light	96	11,628	U	5,504	88	4,665	+17	−59	−42
Otter Tail Power	97	11,840	U	1,891	3	0	−14	0	0
Central Telephone & Utilities	98	12,190	D	743	16	7,735	+47	−20	−19
Montana-Dakota Utilities	99	12,891	U	1,614	13	34	+9	+44	−48
Texas-New Mexico Power	100	17,221	U	0	3	27	0	−	−95

3.8 million tons,

- Middle South Utilities...+69 percent to 5.2 million,
- Delmarva Power & Light...+50 percent to 3 million,
- Houston Lighting & Power...+36 percent to 8.5 million,
- Public Service of New Mexico...+27 percent to 4.6 million,
- Southwestern Public Service...+21 percent to 4.3 million,
- Kansas Power & Light...+17 percent to 5.5 million,
- Wisconsin Public Service...+15 percent to 3 million,
- Wisconsin Power & Light...+14 percent to 3.2 million,
- Consumers Power...+13 percent to 5.9 million,

TABLE 3
TYPE OF GENERATION (MW)

Type	1982	Change	1983	Change
Conventional steam and combined cycle	339,714	+0.9%	338,646	−0.3%
Hydro and pumped storage	25,148	+7.4%	24,613	−2.1%
Gas turbines and internal combustion	36,940	+0.8%	37,488	+1.5%
Nuclear	43,131	−0.2%	46,604	+8.1%
Total	444,933	+1.2%	447,351	+0.5%

TABLE 4
TOP 20 GENERATING UNITS— BY HEAT RATE (CF > 50%)

	Unit	Capacity (MW)
1.	Marshall 3	630
2.	Belews Creek 2	1120
3.	Marshall 1	385
4.	Marshall 4	630
5.	Campbell 3	719
6.	Trenton Channel 9	500
7.	Belews Creek 1	1120
8.	Marshall 2	385
9.	Canal 1	568
10.	Morgantown 2	582
11.	Moss Landing 1	812
12.	Bay Shore 4	215
13.	McMeekin 1	126
14.	Bay Shore 1	136
15.	Karn 1	265
16.	Karn 2	265
17.	Lee 3	252
18.	Big Sandy 1	260
19.	Eastlake 5	446
20.	Milliken 2	154

- Northern Indiana Public Service...+13 percent to 5.1 million,
- Wisconsin Electric Power...+12 percent to 5.6 million.

Efficiency improves

One of the more puzzling results in this year's top 100 data is a significant improvement in thermal efficiency.

In recent years about half the top 100 companies have shown improvements, half have recorded deterioration in heat rates, and the overall average has slowly increased.

That trend seemed to make sense with an aging fleet of power plants and the few new ones degrading overall heat rates since they were loaded down with efficiency-robbing pollution control equipment. Also, flat or declining capacity factors in response to weak energy demand tended to degrade heat rates.

There was a major turnaround in efficiency in 1983 which is difficult to explain with the modest increase in energy output. In 1983 an impressive 63 of the 100 largest investor-owned utilities logged reductions in heat rates. The median heat rate plunged to 10,650 Btu/kWh. That compares to 10,790 in 1982, 10,725 in 1981, and 10,655 in 1980.

The individual system heat rates are shown in the first large table. Changes in the top 10: Cincinnati Gas

Utility	Heat rate (Btu/kWh)
Duke Power	9021
Duke Power	9031
Duke Power	9033
Duke Power	9125
Consumers Power	9135
Detroit Edison	9140
Duke Power	9188
Duke Power	9214
Commonwealth Energy	9216
Potomac Electric Power	9250
Pacific Gas & Electric	9298
Toledo Edison	9321
South Carolina Electric & Gas	9351
Toledo Edison	9367
Consumers Power	9374
Consumers Power	9384
Carolina Power & Light	9389
American Electric Power	9397
Cleveland Electric Illuminating	9428
New York State Electric & Gas	9432

PEAK DEMAND AND CAPABILITY

Company	Season Peak MW	% Change	Winter (W) or Summer (S)	Total System Capacity MW (at time of peak)	Total System Reserve %	Owned Capacity MW (at time of peak)	Owned Reserve %	Load Factor %
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Boston Edison	2,233	+2.4	S	2,809	26	2,716	22	59.0
Carolina Power & Light	6,622	+0.3	S	8,406	27	8,256	25	56.5
Central & South West	9,567	+4.5	S	12,285	28	12,167	27	55.3
Central Hudson Gas & Electric	663	−0.4	S	931	40	973	47	65.4
Central Illinois Light	983	+1.0	S	1,285	31	1,285	31	51.3
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Cincinnati Gas & Electric	3,314	+12.0	S	4,030	22	4,030	22	55.5
Cleveland Electric Illuminating	3,404	+10.1	S	4,533	33	4,341	28	61.9
Commonwealth Edison	14,517	+11.1	S	16,850	16	15,856	9	52.7
Commonwealth Energy Systems	663	−0.3	S	859	30	225	−66	63.4
Consolidated Edison	7,388	+1.2	S	9,884	34	9,330	26	49.6
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Duquesne Light	2,184	+1.2	S	3,088	41	3,063	40	61.3
Eastern Utilities Associates	700	+2.8	S	856	22	556	21	68.4
El Paso Electric	746	+0.3	S	988	32	988	32	61.8
Empire District Electric	536	+6.1	S	629	17	622	16	52.1
Florida Power & Light	10,676	−1.9	S	11,685	9	12,910	21	56.0
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Idaho Power	2,091	−0.1	S	2,666	27	2,486	19	63.0
Illinois Power	3,215	+8.9	S	4,128	28	3,809	18	56.7
Indianapolis Power & Light	2,065	+7.3	S	2,528	22	2,528	22	54.9
Interstate Power	786	+3.4	S	904	15	902	15	60.0
Iowa Electric Light & Power	985	+7.1	S	1,200	22	999	1	53.4
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Kansas Power & Light	1,853	+7.8	S	2,527	36	2,681	45	47.0
Kentucky Utilities	2,399	+3.0	S	2,676	12	2,610	9	53.5
Long Island Lighting	3,108	+2.1	S	NA	–	NA	–	NA
Louisville Gas & Electric	1,885	+13.4	S	2,438	29	2,438	29	49.4
Madison Gas & Electric	426	+10.1	S	594	39	594	39	51.4
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Nevada Power	1,446	+1.8	S	1,962	36	1,750	21	48.9
New England Electric System	3,233	+2.0	S	4,197	30	3,902	21	61.2
New York State Electric & Gas	2,175	+4.0	W	2,779	28	1,799	17	64.4
Niagara Mohawk Power	5,625	+2.1	W	7,705	37	5,315	−6	66.4
Northeast Utilities	4,045	−0.1	S	5,928	47	6,252	55	64.3
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Otter Tail Power	546	+2.6	W	647	18	595	9	57.7
Pacific Gas & Electric	13,243	+8.4	S	17,285	31	11,571	−13	61.7
Pacific Power & Light	4,380	+5.6	W	5,197	19	3,894	11	57.0
Pennsylvania Power & Light	4,869	+8.5	W	7,494	54	7,415	52	62.4
Philadelphia Electric	5,879	+3.3	S	7,503	28	7,503	28	57.4
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Public Service of New Mexico	998	+4.3	S	1,479	48	1,479	48	64.6
Public Service Electric & Gas	7,244	+2.9	S	9,619	33	8,999	24	52.6
Puget Sound Power & Light	3,922	+10.2	W	3,676	−6	1,257	−68	43.1
Rochester Gas & Electric	1,037	+4.1	S	1,536	48	1,183	14	63.9
San Diego Gas & Electric	2,068	+1.1	S	2,677	29	2,577	25	34.6
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Southern Indiana Gas & Electric	963	+30.3	S	1,012	5	1,012	5	50.1
Southwestern Public Service	2,581	+8.2	S	3,576	39	3,633	41	63.3
Tampa Electric	2,092	−7.4	W	2,578	23	2,578	23	60.8
Texas-New Mexico Power	NA	NA	NA	NA	NA	NA	NA	NA
Texas Utilities	14,029	+6.2	S	17,957	28	17,862	27	55.4
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Virginia Electric & Power	9,404	+5.9	S	11,204	19	10,108	7	55.4
Washington Water Power	1,661	+6.7	W	1,804	9	1,389	16	48.8
Wisconsin Electric Power	3,556	+11.3	S	4,196	18	4,274	20	60.3
Wisconsin Power & Light	1,403	+12.1	S	1,822	30	1,637	17	61.3
Wisconsin Public Service	1,166	+5.9	S	1,683	44	1,671	43	72.6

TYPE OF GENERATION IN THE SYSTEM

Company	Fossil			Hydro & Pump Storage			Combustion Turbines			Nuclear		
	MW	%	Last Year Change MW	MW	%	Last Year Change MW	MW	%	Last Year Change MW	MW	%	Last Year Change MW
[illegible]												
Boston Edison	1,797	65	−9	0	–	–	302	11	27	670	24	–
Carolina Power & Light	5,068	61	+587	214	3	–	1018	12	–	1955	24	−90
Central & South West	12,196	100	+136	0	–	–	0	–	–	0	–	–
Central Hudson Gas & Electric	893	92	+56	43	4	−2	38	4	−5	0	–	–
Central Illinois Light	1,255	98	+53	0	–	–	32	2	–	0	–	–
[illegible]												
Cincinnati Gas & Electric	3,555	88	+6	0	–	–	475	12	–	0	–	–
Cleveland Electric Illuminating	3,527	81	−259	305	7	−25	62	1	–	447	10	–
Commonwealth Edison	9,653	55	−21	624	4	–	1331	8	−308	5929	34	+1078
Commonwealth Energy Systems	1,023	94	+2	0	–	–	62	6	–	0	–	–
Consolidated Edison	6,444	69	−126	0	–	–	2037	22	−13	849	9	–
[illegible]												
Duquesne Light	2,457	78	+4	0	–	–	306	10	–	385	12	–
Eastern Utilities Associates	509	92	+2	0	–	–	47	8	−1	0	–	–
El Paso Electric	921	93	−1	0	–	–	69	7	–	0	–	–
Empire District Electric	412	66	−7	16	3	–	195	31	–	0	–	–
Florida Power & Light	8,186	63	−593	0	–	–	1977	15	−2	2823	22	+714
[illegible]												
Idaho Power	858	33	–	1658	65	−17	50	2	–	0	–	–
Illinois Power	3,626	95	–	2	–	–	178	5	–	0	–	–
Indianapolis Power & Light	2,463	97	–	0	–	–	65	3	–	0	–	–
Interstate Power	870	94	+23	0	–	–	55	6	–	0	–	–
Iowa Electric Light & Power	481	49	−19	0	–	–	158	16	–	350	35	–
[illegible]												
Kansas Power & Light	2,342	87	+369	0	–	–	339	13	−2	0	–	–
Kentucky Utilities	2,581	97	−14	24	1	–	59	2	–	0	–	–
Long Island Lighting	NA	–	–	NA	–	–	NA	–	–	NA	–	–
Louisville Gas & Electric	2,237	95	−105	0	–	–	109	5	1	0	–	–
Madison Gas & Electric	409	69	−3	0	–	–	92	15	+2	93	16	1
[illegible]												
Nevada Power	1,312	75	+250	0	–	–	438	25	−30	0	–	–
New England Electric System	2,648	68	+17	1177	30	0	56	2	−75	0	–	–
New York State Electric & Gas	1,733	96	+2	56	3	+18	10	1	–	0	–	–
Niagara Mohawk Power	3,701	70	+33	694	13	+86	310	6	–	610	11	–
Northeast Utilities	2,485	43	–	1264	22	–	523	9	+22	1520	26	−9
[illegible]												
Otter Tail Power	504	85	−19	5	1	+1	87	15	−15	0	–	–
Pacific Gas & Electric	8,275	74	−6	2507	22	+114	394	4	–	0	–	–
Pacific Power & Light	2,982	74	–	976	24	–	26	1	–	27	1	–
Pennsylvania Power & Light	5,685	78	−100	146	2	–	539	7	–	945	13	+945
Philadelphia Electric	3,389	43	–	1392	17	–	1362	17	+26	1816	23	–
[illegible]												
Public Service of New Mexico	1,397	98	−56	0	–	–	28	2	+8	0	–	–
Public Service Electric & Gas	4,312	48	+4	165	2	–	2705	30	–	1817	20	–
Puget Sound Power & Light	508	40	–	310	24	–	455	36	–	0	–	–
Rochester Gas & Electric	605	53	+4	47	4	–	29	3	–	470	41	–
San Diego Gas & Electric	1,752	73	−191	0	–	–	333	14	–	301	13	+214
[illegible]												
Southern Indiana Gas & Electric	879	87	+2	0	–	–	135	13	–	0	–	–
Southwestern Public Service	3,480	97	+32	0	–	–	106	3	+66	0	–	–
Tampa Electric	2,420	94	+40	0	–	–	158	6	–	0	–	–
Texas-New Mexico Power	39	78	–	0	–	–	11	22	–	0	–	–
Texas Utilities	17,856	100	–	0	–	–	6	–	–	0	–	–
[illegible]												
Virginia Electric & Power	6,026	61	−119	326	3	–	439	4	−111	3112	31	−197
Washington Water Power	239	19	42	946	74	−946	101	8	–	0	–	–
Wisconsin Electric Power	2,725	68	+259	7	2	−68	288	7	–	990	25	–
Wisconsin Power & Light	1,195	74	−11	42	3	–	174	11	−4	214	13	+3
Wisconsin Public Service	1,237	73	−7	56	3	–	190	11	+3	214	13	+2

& Electric moved from 21st in 1982 (10,276) to 6th with a heat rate of 10,009; Consumers Power moved from 22nd (10,285) to 8th with 10,054; Dayton Power & Light moved from 20th (10,275) to 9th with 10,063; and Florida Power moved from 26th (10,383) to 10th with 10,082.

It should be noted that system heat rates are a measure of the efficiency of a company's entire thermal capacity. A company's rank is meaningful when compared to other companies with a similar fuel mix and generating characteristics or, more importantly, with its own position over time.

For example, it is not fair to compare a company burning low-rank coal loaded with ash and moisture with a company burning high-grade eastern bituminous coal. Likewise a company operating coal-fired plants grandfathered from federal pollution control requirements should not be compared to a company operating new capacity with sulfur dioxide scrubbers.

In that light, performances of companies further down the list can be impressive when put in perspective. For example, Missouri Public Service moved from 67th place in 1982 with a heat rate of 10,965 to 44th place in 1983 at 10,582. That's an efficiency improvement of almost 4 percent in one year, best among the top 100. Delmarva Power & Light moved from 70th at 11,004 to 47th with a heat rate of 10,634.

Table 5 shows a purer heat rate ranking. Unlike the system heat rate numbers in the large table, this rating eliminates the effect of gas turbines, internal combustion engines, and nuclear plants. It is based only on fossil-fired boilers, the capacity on which utilities concentrate efforts to improve efficiency. The list also shows an overall improvement in efficiency. A heat rate of 10,000 was barely good enough to make the top 10.

There are signs of a resurgence of interest in supercritical plants as a way to improve generating efficiency

TABLE 5
SYSTEM HEAT RATE LEADERS—FOSSIL-FUELED BOILERS ONLY

	Utility	Heat rate (Btu/kWh)
1.	Duke Power	9,343
2.	Consumers Power	9,674
3.	Commonwealth Energy	9,805
4.	American Electric Power	9,815
5.	United Illuminating	9,908
6.	Florida Power	9,953
7.	South Carolina Electric & Gas	9,962
8.	Cincinnati Gas & Electric	9,998
9.	Detroit Edison	10,031
10.	Toledo Edison	10,049

(see *EL&P*, July, page 32.) It is interesting to note that of the 144 supercritical units built by U.S. utilities, only 6 show up on a list of the 20 most efficient generating units shown on Table 4.

Not too impressive

If you remove the Duke Power units from the list, 4 supercritical (Belews Creeks 1 and 2, Marshall 3 and 4) and 2 subcritical, you're left with only 2 of the remaining 14 being supercritical. Since supercritical units were built to achieve high efficiency, that's not too impressive. It's interesting to note that the average size of the 14 non-Duke units is 380 MW. Modest size and high efficiency seem to go together.

The most efficient generating units are largely small subcritical types.

Advocates of supercritical units argue that data put in proper perspective show that supercritical performance has been no worse than subcritical performance in terms of availabilty. However, efficiency data seem to show that supercritical units are no better than subcritical on that score.

Admittedly, the data reported here are sketchy and don't support a strong conclusion. What's needed is a comprehensive comparison of efficiencies of supercritical and subcritical units to eliminate age effects, pollution control equipment differences, and other extraneous factors.

Capability flat

Finally, the data on generating capacity shows a balance between retirements and new capacity. If it weren't for four new nuclear plants showing up in the top 100 data for the first time, the group's generating capacity would have declined for the first time since *EL&P* began tracking it. As it was, the nuclear additions barely canceled out losses in the other categories.

Utilities showing the largest reductions in conventional (non-nuclear) steam capacity were:

- Southern Calfornia Edison...-1128 MW,
- Florida Power & Light...-593 MW,
- Portland General Electric...-534 MW,
- Allegheny Power...-445 MW,
- Ohio Edison...-288 MW,
- Dayton Pwr & Lt...-195 MW.

TRANSMISSION AND DISTRIBUTION LINES IN OPERATION

	Transmission				Distribution							
					Overhead				Underground			
Company	189 kV & Up (circuit miles)	Miles Added	Below 189 kV (circuit miles)	Miles Added	22 kV & Up (pole miles)	Miles Added	Below 22 kV (pole miles)	Miles Added	22 kV & Up (cable miles)	Miles Added	Below 22 kV (cable miles)	Miles Added
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Boston Edison	160	–	199	–	3,373*	4*	–	–	7,173*	89*	–	–
Carolina Power & Light	2,632	98	3,045	–18	36,240*	220*	–	–	2,604*	194*	–	–
Central & South West	1,113	–	14,224	383	237	28	53,137	2408	0	–	4,914	286
Central Hudson Gas & Electric	76	–	521	–82	44	–	6,263	47	0	–	665	7
Central Illinois Light	47	–1	286	–	628	1	5,635	–11	7	–	1,624	34
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Cincinnati Gas & Electric	379	–1	1,377	–2	483	–1	8,903	22	21	1	1,598	56
Cleveland Electric Illuminating	359	103	1,997	–5	–	–	9,434*	15*	–	–	4,866*	113°
Commonwealth Edison	2,383	–	2,444	3	35,587*	18*	–	–	20,056*	303*	–	–
Commonwealth Energy Systems	293	0	60	0	1,414	51	3,279	–15	688	48	1,960	171
Consolidated Edison	410	81	22	–	354^	7^	25,696^	–69^	6,310	5	58,107	–37
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Duquesne Light	132	–	511	–	392	6	6,103	35	392	32	2,032	49
Eastern Utilities Associates	75	–	289	–	65	–	3,335	–	6	–	851	–
El Paso Electric	462	1	654	–	1,271	–248	2,893	19	64	19	644	13
Empire District Electric	0	–	1,190	10	0	–	4,522	43	0	–	204	8
Florida Power & Light	2,494	78	2,235	–26	32,507*	677*	–	–	9,535*	534*	–	–
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Idaho Power	1,451†	–22†	3,229†	–12†	3,911	135	13,055	–92	127	11	4,115	108
Illinois Power	485	36	2,357	22	1,331	–40	16,416	62	4	–	969	27
Indianapolis Power & Light	419	39	617	–	0	–	4,617	12	0	–	3,444	161
Interstate Power	69	–	2,615	–29	NA	–	NA	–	0	–	490	24
Iowa Electric Light & Power	67	–	3,232	–366	0	–	4,698	8	0	–	1,502	42
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Kansas Power & Light	4,348*	–	–	–	12,162*	–	–	–	385*	–	–	–
Kentucky Utilities	433	–	4,119	–14	0	–	13,841	104	0	–	0	–
Long Island Lighting	NA	–	NA	–	NA	–	NA	–	NA	–	NA	–
Louisville Gas & Electric	131	–	758	121	87	–	3,249	13	–	–	1,719*	29*
Madison Gas & Electric	124	–	179	14	0	–	1,076	3	0	–	503	31
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Nevada Power	613	32	458	7	0	–	2,616	26	0	–	2,378	163
New England Electric System	602	0	1,980	–14	785	1	16,046	–742	199	5	6,522	–254
New York State Electric & Gas	4,565*	–	–	–	32,017*	–	–	–	1,533*	–	–	–
Niagara Mohawk Power	1,116	–	8,134	–19	107,345^*	92^*	–	–	6,510*	92*	–	–
Northeast Utilities	2,065*	–	–	–	20,762*	85*	–	–	5,292*	144*	–	–
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Otter Tail Power	369	75	5,029	–285	147	–18	927	209	21	17	1,349	–238
Pacific Gas & Electric	17,854*	–	–	–	81,794*	–	–	–	9,474*	–	–	–
Pacific Power & Light	3,226	–	3,847	–	27,685*	–919*	–	–	6,866*	–2748*	–	–
Pennsylvania Power & Light	1,312	–	0	–	2,348	9	46,529	293	10	–	6,026	2186
Philadelphia Electric	673	–	365	–27	61	4	11,674	10	17	–	14,633	368
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Public Service of New Mexico	2,343*	–	–	–	4,329*	–	–	–	1,656*	–	–	–
Public Service Electric & Gas	680	–2	1,802	6	14*	–	–	–	109	–	19,492	753
Puget Sound Power & Light	336†	16†	1,447†	126†	12,430*	343*	–	–	4,358*	303*	–	–
Rochester Gas & Electric	0	–	701	–12	0	–	6,602	4	0	–	4,095	50
San Diego Gas & Electric	243	33	1,098	4	0	–	7,231	13	0	–	5,598	223
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Southern Indiana Gas & Electric	0	–	804	–	0	–	3,176	5	0	–	619	37
Southwestern Public Service	5,122*	–	–	--	15,096*	–	–	–	847*	–	–	–
Tampa Electric	1,100*	–	–	–	6,345*	–	–	–	1,465*	–	–	–
Texas-New Mexico Power	20	–	1,551	13	–	–	7,805*	307*	–	–	307*	32*
Texas Utilities	3,650	189	8,669	8	2,638	157	47,015	311	770	104	6,436	350
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Virginia Electric & Power	2,666	151	2,984	–30	38,039*	120*	–	–	11,073*	446*	–	–
Washington Water Power	545†	7†	1,477†	–39†	576	2	8,703	8	0	–	1,187	35
Wisconsin Electric Power	2,424*	–	–	–	22,131*	–	–	–	7 475*	–	–	–
Wisconsin Power & Light	107	–	2,759	15	16,700*	51*	–	–	0	–	1,022	85
Wisconsin Public Service	124	–	1,569	–9	16,377*	62*	–	–	3,114*	184*	–	–

*Total—All voltage levels †Pole miles ^Wire miles °Conduit bank miles

Utilities aim at turning around the decline in nuclear plant performance

Robert Smock
Managing Editor

While headlines focus on the problems of nuclear plants under construction, utility attention is concentrating on the 80 nuclear generating units now operating.

They're getting attention because, on average, they're not operating nearly as well as they should be.

The clearest indicator of that is plant capacity factor. It's averaged 60 percent in the U.S. It should be close to 80 percent. Another indicator is availability, less than 70 percent. Even worse, both these indicators have been deteriorating over the past five years.

With the construction pipeline emptying, utilities operating nuclear plants will be able to concentrate efforts on turning around the decline in plant performance.

"Operational quality is the last frontier," Michael Tuckman, manager of Duke Power's Oconee nuclear station told a recent meeting of the Atomic Industrial Forum held to discuss positive experiences in the industry. A program at Oconee and one at Georgia Power's Plant Hatch to improve plant capacity factors were the most positive experiences explored at the meeting.

Tuckman said Oconee has been running at close to the national average of 60 percent capacity factor during its 10-year life. That kind of capacity factor, said Tuckman, is "mediocre." He said 80 percent should be the station's goal.

Georgia Power vice president for nuclear power Dick Conway told the AIF conference that his company's 8-year old Plant Hatch has operated with a capacity factor in the mid 50s and that the goal is to get it up to 75 to 80 percent within three years.

Higher CFs possible

The reason these utilities and others are trying to improve plant capacity factors rather than passively blaming their problems on outside influences beyond their control is that there is evidence that the effort will pay off.

Impressivly high capacity factors and availabilities are being achieved in the U.S., according to a presentation at the AIF meeting by consultant Thomas Keenan, vice president of Cygna Energy Services. While the lifetime capacity factor average for all U.S. plants is 63 percent, Keenan reported, the average for the 17 best plants is 75 percent. Likewise, the best 17 have logged an average plant availability of 80.6 percent compared to 68.6 percent for all U.S. plants.

The U.S. performance looks especially improvable when compared to performance by nuclear plants in other countries. One speaker at the AIF meeting presented a ranking of nuclear capacity factors by nation, reproduced in Figure 1. The U.S. ranks far down the list, outperformed even by developing countries such as South Korea and Taiwan. The top 6 nations have shown it's possible to achieve capacity factors at or near 80 percent.

Unfortunately, presentations by speakers from several European countries ranked above the U.S. on the list were not too illuminating. They've experienced the same problems as U.S. utilities—PWR steam generator corrosion, BWR pipe cracking, regulatory delays, etc.—but to a lesser degree. They seemed to have no magic formulas for solving the problems.

The striking features about most of the European nuclear programs are their small size, as shown in the cumulative energy production totals in Figure 1, and the centralized nature of their utility industries. Unfortunately, neither of these advantages, if they are advantages, are available to the U.S.

Figure 1
Average nuclear plant capacity factors and electricity generation totals for Western nations through the end of 1983 show the U.S. is well down the list.

		Load Factor %	Total Electricity Generation TWh
1.	Switzerland	81.6	121
2.	Netherlands	81.1	40
3.	Finland	79.1	68
4.	Canada	79.0	351
5.	Belgium	78.6	118
6.	Argentina	77.5	23
7.	United Kingdom	69.8	647
8.	Spain	68.8	92
9.	Taiwan	68.5	60
10.	Fed. Rep. of Germany	64.3	439
11.	Sweden	64.2	242
12.	S-Korea	64.0	25
13.	France	61.5	616
14.	Japan	59.4	631
15.	USA	58.2	2756
16.	Yugoslavia	57.6	7
17.	Italy	56.3	70
18.	India	45.4	35
19.	Pakistan	25.0	4
Average of all reactors		62.3	

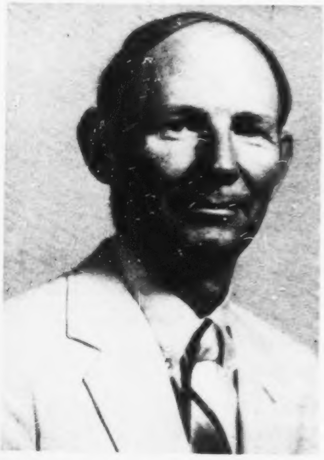
Source: "Swiss Experience in Nuclear Power Operation," Kueffer. International Conference on Positive Experience in Building and Operating Nuclear Power Plants. AIF Boston, May 1984

More interesting was a presentation from a Japanese speaker who outlined nuclear experience closer to that of the U.S. than most of the others. The Japanese have one of the largest nuclear programs outside of the U.S., with 24 units now in operation, mostly of U.S. design.

The capacity factor trend lines in Figure 2 show that in the past the Japanese had even more problems than U.S. utilities. Over the last five years, however, Japan has shown steady improvement while the U.S. plants have steadily deteriorated in performance.

The simple explanation is that the regulatory aftermath of the March, 1979 TMI incident negatively affected U.S. nuclear plants while the Japanese were free to move up the learning curve. That may be true, but the important lesson is that the Japanese experience illustrates it is possible to move up the learning curve and achieve significant improvements in

Continued on next page



Georgia Power nuclear vp Richard Conway thinks significant capacity factor improvement is possible.

The capacity-factor goal for Georgia Power's Plant Hatch is 80 percent.

It can be done—some U.S. nuclear plants are already among the world's best performers.

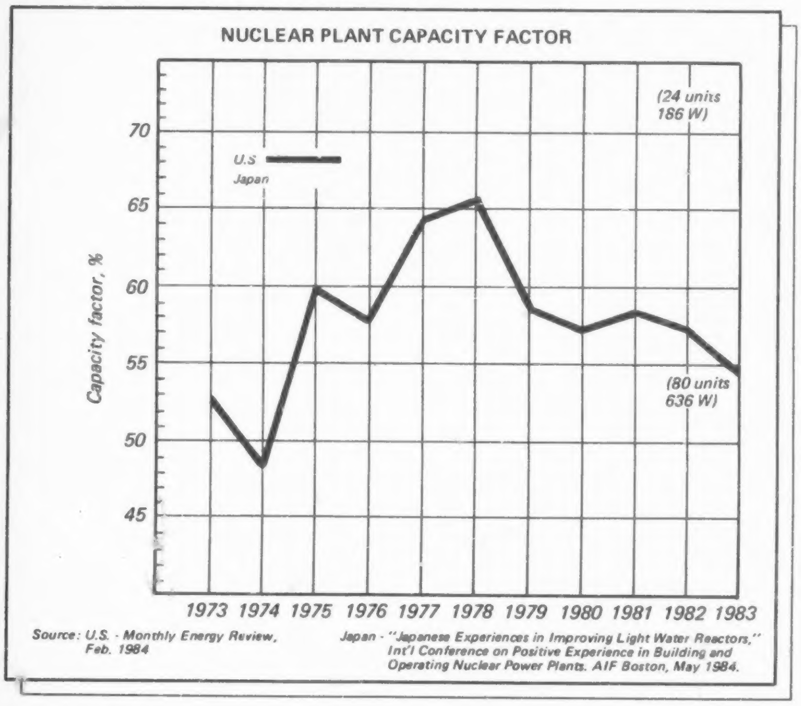
nuclear plant capacity factors in an operating environment that is similar to that of the U.S. in many ways.

Norio Suzuki, managing director of the Japan Atomic Power Co. said that, over the years, Japanese operators of nuclear plants have improved performance by getting past the generic steam generator and pipe crack problems, by introducing more home-grown technology, and, most importantly, by concentrating on reducing outage times.

The Japanese, particularly sensitive to nuclear facilities, require that each reactor be inspected by a government agency during its required annual shutdown, Suzuki explained. That led to extremely long outages in the past which ran as long as 6 months. Introduction of improved inspection and maintenance techniques has reduced the average to about 90 days. In addition, many plants are moving to extended operations, aiming at 13 months of operation followed by 3 months, or less, for the inspection outage. Achievement of an average capacity of 71.5 percent in 1983 with a three-month average for scheduled outages shows that the Japanese have done a good job of reducing forced outages.

Another indicator that it is possible to operate a nuclear plant in the U.S. at a capacity factor close to the best in the world is shown in Figure 3—some are already there.

The capacity-factor trendlines over the past 10 years for U.S. and Japanese nuclear plants shows a sharp divergence in direction since 1978.



Source: U.S. - Monthly Energy Review, Feb. 1984

Japan - "Japanese Experiences in Improving Light Water Reactors," Int'l Conference on Positive Experience in Building and Operating Nuclear Power Plants. AIF Boston, May 1984.

The best-performing nuclear units in the world include several from the U.S. These are cumulative capacity-factors through the end of 1983 for all units larger than 100 MW with more than three years of operation.

1.	Beznau-2	CH	PWR	364 MW	85.8% since Dec 1971
2.	Muehleberg	CH	BWR	336 MW	85.4% since Nov 1972
3.	Stade-1	FRG	PWR	662 MW	84.4% since May 1972
4.	Doel-1	B	PWR	412 MW	83.2% since Feb 1975
5.	Unterweser	FRG	PWR	1300 MW	82.8% since Dec 1979
6.	Goesgen	CH	PWR	970 MW	81.3% since Oct 1979
7.	Borssele-1	NL	PWR	481 MW	81.2% since Oct 1973
8.	Olkiluoto-1	FIN	BWR	683 MW	80.8% since Oct 1979
9.	Obrigheim	FRG	PWR	345 MW	80.4% since March 1969
10.	Point Beach-2	USA	PWR	524 MW	79.7% since Oct 1972
11.	Oskarshamn-2	S	BWR	615 MW	79.4% since Dec 1974
12.	Prairie Island-2	USA	PWR	547 MW	79.0% since Dec 1974
13.	Connecticut Yankee	USA	PWR	602 MW	79.0% since Jan 1968
14.	Barsebaeck-2	S	BWR	590 MW	77.8% since July 1977
15.	Calvert Cliffs-2	USA	PWR	880 MW	76.9% since March 1977
16.	Chinshan-2	TAI	BWR	636 MW	76.7% since July 1979
17.	Kewaunee	USA	PWR	560 MW	76.5% since June 1974
18.	Tihange-1	B	PWR	920 MW	75.8% since Oct 1975
19.	Beznau-1	CH	PWR	364 MW	75.4% since Dec 1969
20.	Loviisa-1	FIN	PWR	465 MW	75.3% since May 1972

Source: "Swiss Experience in Nuclear Plant Operation," Kueffer, International Conference on Positive Experience in Building and Operating Nuclear Power Plants. AIF Boston, May 1984

There's a plaque at Plant Hatch that says the station's goal is to be "the best nuclear power plant in the USA" and it's signed by all the station employees, reported Georgia Power vice president Dick Conway.

The utility defines "best" at least partially in terms of capacity factor. The goal is to get the plant into the 75 to 80 percent range. Plant Hatch, a twin unit BWR station with the first unit in operation for about 8 years, has logged a capacity factor in the mid 50's.

Right now the plant is in the middle of a recirculation piping replacement, a capacity-factor robbing project common to many BWRs. (Conway said there are 2100 people on site for the replacement job, more than were needed at the peak of plant construction.) Following completion of the replacement project, the capacity factor improvement effort will begin.

Conway said the company expects to get half the CF improvement through modifications of plant equipment. Changes in operating procedures will account for 10 percent of improvement and better maintenance practices will produce the rest.

Utility analysts looked at 200 potential sources of power losses and identified 128 potential improvements for Plant Hatch. The importance of the improvements was analyzed on the basis of contribution to plant performance and to regulatory compliance, each factor given equal weighting.

Contribution to regulatory compliance was measured by estimating factors such as reduction in number of violations, dollar value of fines, man-rems of exposure, etc. Contribution to performance was measured by estimated increase in capacity factor, reduction in planned outage days, effect on heat rate, etc. In this manner the potential improvements were ranked. Now the capacity factor improvement program is focussing on the top 49 items, Conway said.

Some of the major modifications will be a cooling tower upgrade, relocation of the steam jet air ejectors, and rebuilding of the condensers.

Duke Power's program

Duke Power's Michael Tuckman explained that even though capacity factors at the three-unit Oconee station ran close to the U.S. average Duke was not very happy with that level of performance.

In 1982 Duke formed a nuclear production department separate from the fossil group. A manager of nuclear reliability assurance was appointed to report to the vice president in charge of nuclear production. The reliability assurance department identified the top 10 items contributing to unreliability at each unit and set up programs to solve the problems.

Tuckman explained that at his station, Oconee, 1982 saw low capacity factors because each of the three units was down for an average of 164 days for a 10-year inspection outage and major repairs.

Duke got the plant back in "first-class" condition, Tuckman reported, and operations since then have been excellent. Despite two refueling outages in 1983 the plant logged an overall capacity factor of 79 percent. So far in 1984 unit 1 and 2 are running at 99 percent CF and unit three at 84.

Tuckman identified these specific steps taken in the Oconee capacity-factor improvement program:

- Poor valve performance, the manager reported, was a major cause of reliability and thermal efficiency problems. An outside vendor was brought in to train mechanics and engineers and valve maintenance procedures were tightened up. Spare parts have been beefed up and bad performers were identified and replaced. In a typical outage in the past 200 valves were repaired said Tuckman, but during the long 1982 outage almost 500 were repaired at Unit 2 alone. In addition, 56 valves were replaced at the Oconee station.
- Since 1976 Oconee has experienced 23 steam generator tube leaks with each outage averaging 330 hours. The improvement program led to steps such as reducing stress on steam generators by taking more care during turbine stop-valve testing to reduce mechanical shock on the tubes and restricting low power operation. Coupled with tighter limits on water and steam chemistry, these steps have produced a significant improvement in steam generator operation. There have been no leaks in the past 17 months.

Modifications made

- There have been a number of equipment modifications such as changes in reactor coolant pump seals and motor lubrication that appear to have solved long-standing generic problems. The station is currently on its third generation of control rod drives and they seem to be performing well, Tuckman reported. The reactor building cooling system was upgraded because temperatures were as high as 140 to 150F, too high for maintenance workers. Temperature was dropped 30 degrees.
- Oconee has moved to a 440-day refueling cycle from a 270-day cycle for each unit. Management is looking at the possibility of a 520-day cycle.

One of the more interesting changes was the move to 12-hour rotating shifts in January of 1983. Tuckman feels that the 12-hour shift results in fewer operator errors because there are fewer shift changeovers, overtime is reduced, and because there is more time per shift to solve complex problems. Tuckman feels the longer shift has resulted in higher worker morale because there are fewer workdays, ten more weekends at home, a 20 percent lower commuting costs. Operations, maintenance, health physics staffs rotate on a common schedule to create a team spirit. Station staff people will soon be moving to the 12-hour shift (with the exception of QA/QC people.) Tuckman said regulators were worried at first about the change because of fears about operator alertness holding up for 12 hours at a time. He said the company has seen no sign of alertness problems so far and there have been no further comments from the regulators.

The 12-hour shift results in a few percent built-in overtime pay, said the manager, but overall overtime has been reduced because of improved productivity. A survey of initial employee attitudes showed 80 percent interested in it. Now, said Tuckman, nearly 100 percent want to keep it, indicating high morale. "By every yardstick, improved employee morale, personnel errors, sickness, absenteeism, and callout overtime," said Tuckman, "we have seen benefits from the 12-hour shift rotation plan."

Summer peak demand to grow at 2.5% rate

SUMMER PEAK DEMAND – MW

Region	Actual 1983	1984	1988	1993	Average Annual Growth (%) 1984-1993
ECAR	65,959	64,008	71,438	79,110	2.4
ERCOT	34,972	36,841	43,061	52,407	4.0
MAAC	34,783	34,720	36,690	39,150	1.3
MAIN	34,704	34,119	36,874	40,165	1.8
MAPP–U.S.	20,785	21,517	23,907	26,728	2.4
NPCC–U.S.	37,627	37,881	40,306	44,006	1.7
SERC	97,235	93,920	106,777	121,873	2.9
SPP	45,881	46,441	51,486	58,970	2.7
WSCC–U.S.	75,580	77,234	86,429	96,961	2.6
NERC–U.S.	**447,526**	**446,681**	**496,968**	**559,370**	**2.5**

SOURCE: North American Electric Reliability Council

PRINCETON, NJ—Over the next decade summer peak demand in the U.S. will increase at an annual rate of 2.5 percent, according to the North American Electric Reliability Council (NERC).

NERC said it estimates that summer peak demand will be 446,681 MW this year, compared to 447,526 MW in 1983. The summer peak demand will steadily rise over the next several years hitting 559,370 MW in 1993, said NERC.

The council released selected data in advance of publication of its *Electric Power Supply & Demand 1984-1993* forecast that will be out later this summer. NERC compiles its information from statistics submitted by individual utility members of each of NERC's nine regional councils.

NERC reports that the highest average summer peak demand growth rate will be in the Electric Reliability Council of Texas (ERCOT) region, with a four percent rate.

Summer peak demand is expected to increase only 1.7 percent a year in the Mid-Atlantic Area Council (MAAC) region, which includes portions of Pennsylvania, New Jersey, Maryland and Delaware.

In Canada, summer peak demand is expected to grow at a 3 percent annual rate over the next ten years. NERC said that Canada's 1984 summer peak should be 41,349 MW, compared to 41,014 last year.

U.S. energy sales are expected to increase at an annual rate of 2.7 percent over the next decade, according to NERC. Energy sales will be 2.39 billion MWH in 1984, compared to 2.34 billion MWH in 1983.

The highest growth rate in energy sales will occur in the ERCOT region (4.0 percent), while the lowest (1.8 percent) will be in the MAAC region, according to the NERC data.

Energy sales in Canada over the next ten years are expected to grow at an annual rate of 3.1 percent.

R&D funding not adequate, says Gray

BOSTON—Research and development funding by the electric utility industry is "completely inadequate", according to Massachusetts Institute of Technology President Paul E. Gray.

"Today the research and development efforts of the electric power industry can best be described as disaggregated, episodic and ad hoc," said MIT's Gray.

In a speech presented at the recent annual convention of the Edison Electric Institute, Gray said the R&D efforts of the Electric Power Research Institute don't address issues and problems posed by the coming decades. He said EPRI's current budget of $264 million is not enough.

"Your industry had total revenues last year of $130 billion and represents an in-place capital investment of $345 billion," pointed out Gray. "Even the short term requirements of the industry cannot be met with a research program of $300 million per year—and the longer term needs are simply not addressed in such programs."

The MIT president reminded convention attendees that the electric industry has developed some of the world's most sophisticated and reliable technology. He said the past record of development must be continued at an accelerated pace.

"The challenge," he said, "is to develop a program of basic research and development that can look to the long run needs of the industry, a program that calls on basic engineering sciences to identify and develop the technologies required by the electric power industries for 1995 and beyond."

Gray said it is time to invest in the future.

R&D areas

There are many areas in which new technological developments should make it possible for the utility industry to overcome the problem of acid rain, according to Gray.

Also, he said continued improvements in photovoltaic solar cells will eventually lead to economic solar electric systems for residential and other low-intensity consumers.

"Perhaps the most important area in which fundamental research is needed is in nuclear fission," said Gray. "As we understand the effects of burning coal, particularly the potentially devastating effects on weather patterns caused by increasing carbon dioxide in the atmosphere, our choice of courses for electric energy becomes increasingly limited."

Gray stated that he was convinced that nuclear power "in a new and politically acceptable form" must continue as a source of electric energy and heat.

Massachusetts Institute of Technology President Paul E. Gray says electric industry research and development efforts are "completely inadequate."

Energy innovator awards given to six by APPA

BOSTON—Six consumer-owned electric utilities have been honored by the American Public Power Association for their use of creative energy-efficient techniques and technologies.

The APPA Energy Innovator Award was given to the City of Austin (TX) Electric Utility, Fort Collins (CO) Light and Power, Nashville (TN) Electric Service, City of Palo Alto (CA) Utilities Dept., City of Livingston (MT) and the Sacramento (CA) Municipal Utility District.

The awards are presented through APPA's Demonstration of Energy-Efficient Developments program. Thirteen judges evaluated each entry on the basis of creativity, resource efficiency, benefits to consumers and transferability.

Austin said it plans to reduce its future energy demand by 535 MW through energy management and renewable energy programs.

Fort Collins was honored for its broad program that covers utility operation practices, customer service and educational outreach, community energy assistance and planning.

Under Nashville's Project 2000, high school students provided home repair and weatherization services to low-income, elderly and disabled citizens in 500 homes.

Palo Alto was given an award for its innovative use of a microcomputer.

NARUC supports regional regulation

WASHINGTON, D.C.—During a late June congressional hearing, Iowa Commerce Commission Chairman Andrew Varley urged passage of legislation that would allow states to enter into regional electric utility compacts.

He said that "a voluntary regional framework (for electric utility regulation) will provide state (regulators) the opportunity to evaluate their decisions on a broader scope to ensure that the energy needs of the consumer are met."

Varley, who serves as chairman of the National Association of Regulatory Utility Commissioners (NARUC) electricity committee, told the House subcommittee on energy conservation and power that H.R. 5766 also would shift Federal Energy Regulatory Commission (FERC) jurisdiction over intrastate wholesale power transactions to the states.

NARUC had endorsed a 1983 National Governor's Association report that said states should have the ultimate regulatory authority.

Speaking on behalf of NARUC, Varley said regional energy planning would facilitate the gathering and evaluating of information on the current and future needs and resource characteristic of a particular region.

"This would assist state regulators in developing long-range electric system and conservation plans, in avoiding inconsistent or conflicting regulatory policies and in reacting to emergency situations," he told the committee.

Varley testified that regional cooperation might encourage energy conservation by forcing utilities to make the most efficient use of the generation available in their region.

He recommended that regional planning be implemented on a voluntary basis in order to avoid adding another layer of regulation and to make sure planning decisions are approved by the state regulatory agencies.

A provision of the bill to return the power to regulate intrastate wholesale transactions back to the states received a strong endorsement from NARUC.

Varley said, "This would allow greater coordination of the regulation of intrastate wholesale rates with the regulation of revenues from retail rates currently under state jurisdiction."

NARUC publishes survey on utility regulation bills

WASHINGTON, D.C.—If enacted, a variety of proposals that are pending in different state legislatures could have a significant impact on the future of public utility regulation, according to a new survey.

The National Association of Regulatory Utility Commissioners (NARUC) *Survey of Pending State Legislation pertaining to Utility Regulation* lists bills which have been introduced in seventeen different categories of utility regulation.

NARUC says that at least twelve states currently are considering measures to require the direct election of commissioners.

In addition, the survey lists bills under consideration to restrict the use of automatic fuel adjustment clauses, impede the construction of nuclear plants and establish rules on utility disconnection procedures.

Copies of the 53-page survey may be obtained by sending $6.50 to NARUC, P.O. Box 684, Washington, D.C. 20044.

NOTE

ONLY THE FOLLOWING PAGES OF THIS

PUBLICATION HAVE BEEN FILMED

Cov. 1, p. 2, 15, 23, 43,

55.

BEST AVAILABLE COPY

C8650-4A

Volume 62, Number 9
September 1984

09925 1957257 W 3 2024
JOSEPH MCNALLY
CONGRESSIONAL INFO SERVIC D
4520 EAST WEST HWY STE 800
BETHESDA MD 20814

Electric Light & Power

THE NEWS MAGAZINE OF ELECTRIC UTILITY MANAGEMENT AND TECHNOLOGY

State regulators clarify tasks for EPRI oversight work

Report details research contracting areas needing scrutiny

Dan Utroska
Associate Editor

WASHINGTON, D.C.—Regulatory scrutiny of the research contracting procedures employed by the Electric Power Research Institute (EPRI) is moving forward with deliberate but measurable pace.

A National Association of Regulatory Utility Commissioners (NARUC) resolution in late July has specifically empowered a specially-formed oversight committee to investigate research priorities and procedures at EPRI. The oversight committee was formed last February by another NARUC resolution and was charged with the general responsibility of monitoring and critiquing EPRI research contracting practices.

In addition, a current report issued by a NARUC staff subcommittee details specific areas where EPRI research contracting methods could be improved. The report highlights special points of interest for the oversight committee's attention.

Report has mixed findings

While the NARUC staff subcommittee report found that EPRI's research contracting procedures were "generally acceptable," and further, that the institute's strategic planning provided "a reasonable framework for the selection of individual research projects," it criticized the high percentage of contract awards made without competitive bidding.

The NARUC staff subcommittee report also questioned what it saw as a disproportionately high number of California contractors. EPRI headquarters is based in Palo Alto.

"The fact that 72 percent of EPRI's 1983 contracts, constituting 52 percent of the total contract expenditures, were awarded on a sole source basis, suggests that a greater effort could be made in opening the contracting system to more prospective researchers," the NARUC staff subcommittee report reads.

"Sole source" proposals are a type of noncompetitive means for soliciting research contracts when allegedly there is no real question over contractor identification for specific projects. EPRI's criteria for sole source projects state that explicit justification must be provided for projects that cost more than $200,000.

The NARUC staff subcommittee reviewed 18 recently completed projects. Of the 18, 13 were sole source contracts, and 10 of the 13 were initially contracted at a cost below the $200,000 threshold, thus eliminating the need for sole source justification.

Of the 10 sole source research contracts that initially were below the $200,000 threshold and therefore not subject to sole source justification, four projects had contract amendments that resulted in final costs substantially greater than $200,000.

"This might be interpreted as an effort to circumvent the competitive process in choosing vendors," the staff subcommittee report reads. "Further, initial sole source contracts may contain unrealistic cost estimates or commitments to deliver if future expansion of the contract is anticipated by the vendor. It suggests, at least, that more care should be exercised in making the initial contract award and in choosing a vendor for expanded follow-on research."

In light of these findings, the

Continued on page 3

Montana commission votes to disallow cost of Colstrip-3

HELENA, MT—Disallowing the full cost of the 700 MW coal-fired Colstrip Unit 3, the Montana Public Service Commission (MPSC) has voted to allow Montana Power only $4 million of a $96.4 million rate increase request.

Approximately $60 million of the request was for the cost of Colstrip 3. The utility had asked for a 16.7 percent rate of return and was granted a 11.7 percent return.

Earlier in the summer, the utility, which owns 30 percent each of units 3 and 4, announced it was delaying construction of the 95 percent complete unit 4 until Spring of 1986.

In disallowing Colstrip 3, MPSC Commissioner Howard L. Ellis told *EL&P* that the commission used the Montana "used and useful law" in deciding the unit would not be needed.

Ellis said the commission looked at Montana's firm load and projected the utility would have ample reserves well into 1993.

Short-sighted view

Montana Power spokesman Jim Schwartz vehemently disagreed, saying the MPSC is "taking a very short-sighted view of the situation."

Schwartz said the utility presently can use all of the power generated by unit 3 and some of the electricity to be generated by Colstrip-4 when it goes on-line.

He said the utility will file a reconsideration request with the commission. If that fails, Schwartz suggested the utility might take the matter to the state supreme court.

Other options for the utility, include selling its percentage of the units or selling the power. As of now, Schwartz said, Montana Power has no potential buyer for its share of the units. However, he said there are some utilities in the area that have plans to add generating capacity.

"The commission seems to be deregulating the power from Colstrip-3," said Schwartz. He explained that the utility feels it has gotten an OK to go out and get the highest price for selling the power to outside sources.

The utility spokesman admitted that the situation could still work to the utility's advantage if it can find buyers for the electricity. Schwartz said most of the potential buyers are in the Pacific Northwest where planned nuclear plants have been cancelled.

Cash flow problem

In the meantime, the utility finds itself with a serious cash-flow problem. Schwartz said Montana Power is scrutinizing costs and looking at the possibility of cutting travel, construction, and other business expenses. He said no lay-offs are planned.

MPSC Commissioner Ellis admitted the decision to keep Colstrip out of the rate base puts the cash flow of the utility in a "desparate position."

Ellis said the decision also "hangs Colstrip-4 out as a hazard to the company."

Other owners of the plant include; Puget Sound Power & Light, Portland General Electric, Pacific Power & Light and Washington Water Power Company.

Cogeneration: Is the trend upward?

The Great Western Malting Company's cogeneration facility, located at Vancouver, Washington, supplies heat to roast malted barley while generating enough electricity to heat and light 8,000 homes. The Clark County Public Utility District purchases the electricity from the General Electric LM 2500 facility. Although there is much present optimism about the future of cogeneration through the year 2000, there is not much of a data base from which to project subsequent growth. A special feature for generation readers appears on page 19.

NARUC recommends utilities bring EEI audit to rate cases

Some regulators call NARUC resolution a 'victory'; measure may end probe of Edison Electric Insitute expenditures

WASHINGTON, D.C.—Electric utilities will have to present a current, independent audit of Edison Electric Institute (EEI) activities and expenditures in future rate cases, if a recommendation by the National Association of Regulatory Utility Commissioners is adopted by state regulatory commissioners.

In announcing its recommendation, NARUC encouraged its member commissions across the country to disallow all rate treatment of utility contributions to EEI if a reporting system has not been agreed upon by September 30, 1984, or if an operational audit by an acceptable firm had not been completed by March 31, 1985, 90 days after the close of EEI's fiscal year.

EEI has said that it will meet the September 30 deadline, and at press time Price Waterhouse—the firm

Continued on page 2

Foreign Power Briefs

- **Cuban Prime Minister Fidel Castro** announced plans for his country's first nuclear power plant during a speech delivered in late July. Castro said the plant is being built with Soviet aid and would be located at Cienfuegos, 150 miles southeast of Havana. The prime minister said it will have four, 417 MW reactors built to withstand earthquakes, tidal waves and a jet crash. Castro said the plant is being built with 5,500 Cuban workers, 188 Soviet advisors and 82 Bulgarian volunteers. A completion date for the plant was not announced.

- **China's Ministry of Coal Industry** has contracted Ebasco Services Inc. to develop a coal/water slurry pilot demonstration plant in Peking. According to the $1-million contract, Ebasco will provide engineering and support services for the project. Targeted for completion in Fall 1985, the project will determine the technical and economic feasibility of slurrying Chinese coals.

- **The Japanese government** said it has approved a plan that would authorize construction of 67.7 million kilowatts of generating capacity over the next ten years. A Natural Resources and Energy Agency spokesman said the construction program would include 27 nuclear plants, with a total capacity of 26.5 million kilowatts. The spokesman said the plan reflects Japan's desire to reduce its dependence on foreign oil.

- **Ontario Hydro** reports that electricity exports to the United States increased 8.6 percent in June. The utility sold approximately 926.9 million kilowatthours of electricity to U.S. utilities in June, compared with 853.4 million kilowatthours sold in June 1983. The utility said the power exports earned its customers almost $16.2 million in June. In the first six months of the year, Ontario Hydro said income from its power sales to the U.S. totaled more than $87 million.

- **Kyushu Electric Company of Japan's** Genkai-2 nuclear plant set a world record 415 days of continuous operation in July before shutting down. The previous record was 400 days, held by Fukushima I-2. Northeast Utilities' Connecticut Yankee nuclear plant then broke the mark in July, hitting 417 days of continuous operation. Northeast Utilities Chairman and Chief Executive Officer William Ellis sent a telegram to Kyushu Electric President Tatuo Kawai saying, "What a proud time for the nuclear industry when two reactors on opposite sides of the globe can each surpass 400 days of continuous operation."

- **Ferre Development Inc. of San Juan, Puerto Rico** and Combustion Engineering have formed Caribe Energy Services Incorporated. The joint venture will serve Caribbean electric utilities and industrial steam users in planning and executing new projects, providing maintenance services and upgrading units. Caribe will provide all the services previously offered by Combustion Engineering Americas Inc.

- **Ube Wormser Ltd.,** a new joint venture based in Tokyo, has been formed to produce and market its fluidized bed combustor for clean utilization of low-grade coals. The partners in the new company are Massachusetts-based Wormser Engineering and two large Japanese industrial firms, Ube Industries and Marubeni Corporation. Wormser said the venture will be responsible for the marketing, design and construction of the Wormser Grate fluidized bed combustor in Japan, southeast Asia and Oceania. The initial Japanese installation will be a 65,000 pound-per-hour unit installed in a plastics plant in Ube City.

In This Issue

Editorial 4

Calendar 13

Transmission ties between neighboring utilities are adding a new dimension to integrated electric utility system operations 15

Cogeneration is being touted as a new success story in the wake of federal legislation aimed at stimulating the technology. But some analysts are challenging the validity of that report. **G** 19

Complaints by nuclear project construction workers are being encouraged by Detroit Edison, so they don't grow into last-minute allegations. **G** 22

Microprocessor-based transmission system protection is being developed by EPRI. **T/D** 31

New Products 47

Bulletin Board 50

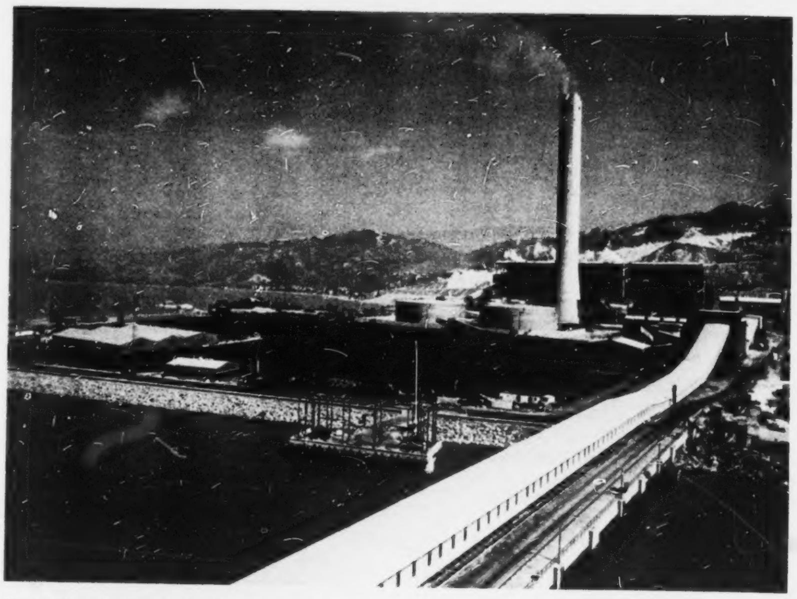
Readers' Service 51

Personnel 58

Regulatory Review 60

Management Methods 62

EL&P readers whose responsibilities include both Generation and Transmission/Distribution receive both technology sections. Other readers receive the technology section that applies to their respective area of responsibility. The Generation edition is indicated by a single dot (•) in the upper right corner of page 1, the T/D edition carries two dots (••). All readers receive EL&P's industry news section.



Hong Kong's Castle Peak coal-fired project, $23-million in Hong Kong dollars, is the largest single order placed in Britain for power generation equipment. Castle Peak-A station, shown here, is expected to be operating at full capacity by the end of the year when the fourth 350 MW unit goes on-line. Construction is underway on Castle Peak-B, which will have four more units coming on-line between 1986 and 1989.

NARUC recommends . . . from page 1

that prepares EEI's audited annual financial statement—was being broadcast as the company to prepare the operational audit.

An operational audit, which reportedly is different from a conventional financial audit, seeks to formally trace both the activities and expenditures of each department within EEI.

Recommendation may end probe

The late July NARUC recommendation is the result of an ongoing probe of EEI expenditures by state regulators. The required audit is to be conducted during the preceding year by an independent group, showing "all direct and indirect contributions to and through EEI from all sources," and additionally, showing "all expenditures by program and by a system of accounts."

During the past year, NARUC's staff subcommittee on accounts has been sending inquiries to EEI in an effort to determine how the institute spends its money. The investigation has been aimed at trying to develop generic guidelines to help state commissions discriminate in rate cases between those EEI expenditures that are in the interest of electricity consumers, and therefore should legitimately be borne by ratepayers, and those that are strictly in the interest of utility shareholders, and therefore should not be passed along through rates.

NARUC has been interested particularly in identifying expenditures for lobbying and regulatory advocacy, including the cost of preparation of materials and persons for these activities (see *EL&P*, February 1984, page 1 and April 1984, page 1).

Also of special interest to NARUC is EEI's advertising expenditures, especially funds used for promoting electricity load growth and for "good will."

During its nearly two-year investigation of EEI expenditures, NARUC regularly has complained that the institute has been less than cooperative in responding to NARUC interrogatories. In fact, as part of its explanation for deciding to require each utility to present an EEI audit in rate cases, NARUC said its staff subcommittee on accounts had not been able, from information supplied by EEI, to determine aggregate amounts annually spent by the institute on advertising, lobbying, and regulatory advocacy.

The NARUC resolution—which likely will result in state commissioners getting an audit of EEI operations and expenses, but not generic guidelines concerning which expenses ought to be allowed—"grew out of a healthy state of frustration," says Michael Foley, NARUC's Director of Financial Analysis.

The frustration was caused by the fact that the NARUC probe of EEI expenditures primarily took place through the mails, as NARUC sent lists of questions and EEI mailed back its responses.

"In a sense, we were at their mercy on this," Foley laments, adding that EEI's responses were "insufficient, contradictory" and in some instances "bordered on falsehood."

"It became clear that we were going to have to take a more aggressive approach," he said, and the resolution reportedly embodies this.

"The resolution represents a victory for those who were pushing for a vigorous, professional effort" on the part of regulators, Foley added.

Asked to comment on the resolution, an EEI spokesman offered a short, formal statement. "EEI has and will continue to cooperate fully with NARUC in developing and implementing a system of reporting on EEI activities which will aid regulators in considering treatment of dues paid to EEI in rate proceedings.

"We believe," the statement added, "that the NARUC resolution approved July 26 provides for development of a method which will meet both the legitimate needs of regulators for information and EEI's needs for clear, mutually-agreed upon definitions on which to provide accounting."

Addressing the quality of EEI's upcoming audit report, NARUC's Foley said, "They can do an awful lot to put this [controversy] behind them, but if the report is insufficient, this will boil up all over again."

As part of its decision to recommend that electric utilities be required to secure EEI audits for presentation at rate cases, NARUC asked that EEI join with it in selecting an auditor acceptable to the insti-

Continued on page 27

Meeting more than summer peak demand

Interconnections provide new operating economies, as well as backup during emergency, peak periods

Robert A. Lincicome
EL&P Editor-in-Chief

BARRINGTON, IL—Transmission ties with neighboring utilities and interconnections between regional pools and coordination councils are adding a new dimension to integrated electric utility system operations. In addition to providing bulk power backup during peak demand periods and emergencies, transmission interconnections are allowing more and more utilities dependent on expensive oil and natural gas as boiler fuel to turn to neighboring utilities with over-abundant coal-fired and nuclear capacity to meet their base-load customer electricity requirements. The result: economic benefits for all.

Since load growth has been lower than anticipated at the time generating system expansion programs were drafted back in the 1970s, many utilities...and all regional coordinating councils...currently are experiencing high generation reserve margins. For those with abundant coal-fired and nuclear capacity, transmission interconnections...both intra- and inter-regional...offer the opportunity of selling the output of at least some of the excess capacity and increasing revenues. For utilities with expensive oil- and gas-fired generating capacity, transmission interconnections provide a source of lower cost electricity, thereby reducing operating costs and the price of electricity delivered to customers.

But nothing ever is totally free and the benefits of more economic operations must be counterbalanced against the potential adverse effect of lack of transmission system operational flexibility. If interconnections, between neighboring utilities and between regions, are operated close to or at their maximum loading levels for a greater portion of the time...as many are currently according to the North American Electric Reliability Council, their ability to withstand and operate under unusual contingencies is reduced.

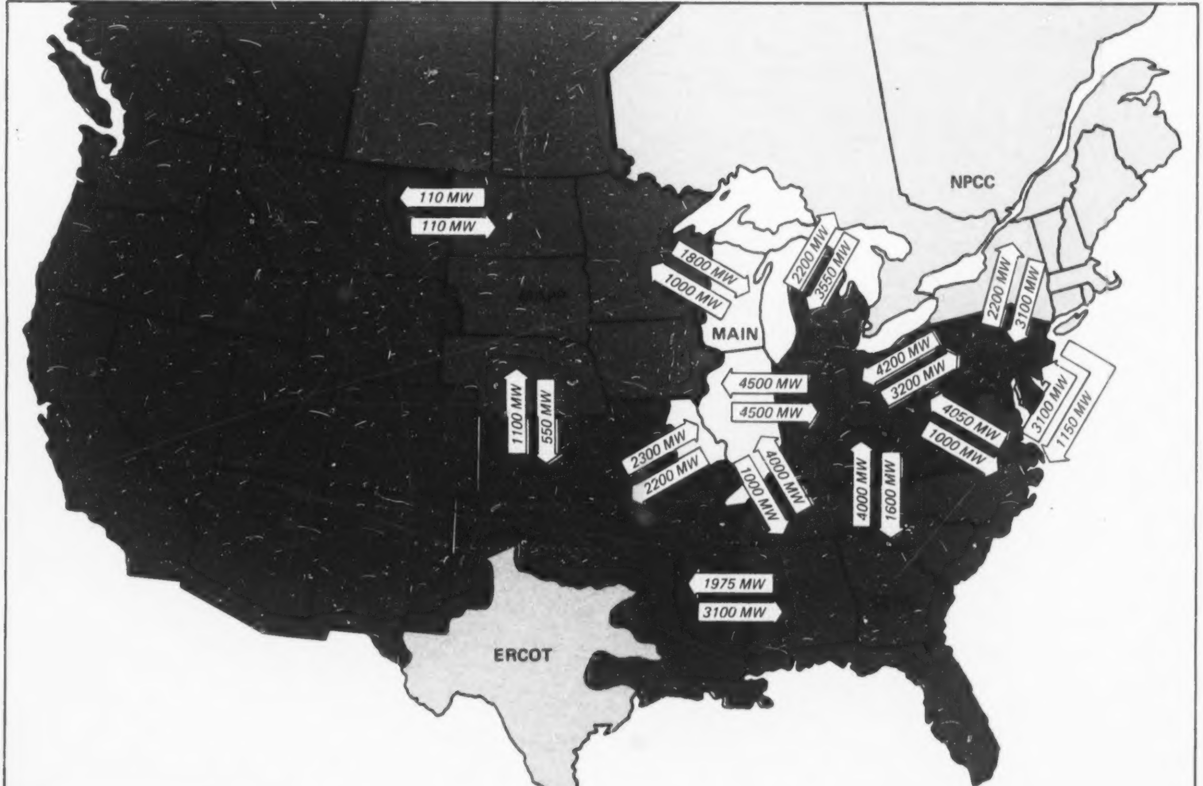
In other words, although the use of transmission interconnections to meet base-load requirements can lead to reduced costs of electricity for consumers, the risk of service interruptions to those customers is increased.

NERC reports that transmission lines into and within certain areas that are heavily dependent on oil- and gas-fired generation are being operated at or near their maximum reliable loading levels most of the time. Such limitations are being reached often within NPCC, MAAC, the Florida subregion of SERC and WSCC. In WSCC, transmission limitations between the Pacific Northwest and California, between the Rocky Mountain systems and the Arizona-New Mexico power areas and between the Arizona-New Mexico area and the California-Nevada area restrict potential transfer of cheaper hydro and other non-oil-based electricity.

The threat to system reliability is greatest at times of peak demand ...which for most American utilities means the months of June, July and August.

REGIONAL RELIABILITY COUNCILS		
ECAR	**East Central Area Reliability Coordination Agreement**, serving all or parts of the states of Michigan, Indiana, Kentucky, Ohio, Pennsylvania, Maryland and Tennessee.	19 member systems
ERCOT	**Electric Reliability Council of Texas**, serving utilities within the state of Texas only.	86 member systems
MAAC	**Mid-Atlantic Area Council**, serving all of Delaware and D.C. and major parts of Pennsylvania, New Jersey, Maryland and a small portion of Virginia.	11 member systems and 5 associates
MAIN	**Mid-America Interpool Network**, serving all of Illinois, the eastern third of Missouri, the eastern two-thirds of Wisconsin and most of the upper peninsula of Michigan.	12 member systems and 2 associate groups
MAPP	**Mid-Continent Area Power Pool**, serving all of the states of Iowa, Minnesota, Nebraska and North Dakota, portions of Illinois, Michigan, Montana, South Dakota and Wisconsin, and the Canadian provinces of Manitoba and Saskatchewan.	46 member systems and 19 associates
NPCC	**Northeast Power Coordinating Council**, serving all of Connecticut, Maine, Massachusetts, New Hampshire, New York, Rhode Island, Vermont and the Canadian provinces of New Brunswick, Ontario and Quebec.	21 member systems
SERC	**Southeastern Electric Reliability Council**, serving all of Alabama, Florida, Georgia, North Carolina, South Carolina and Tennessee, and parts of Kentucky, Mississippi and Virginia.	27 member systems
SPP	**Southwest Power Pool**, serving all of the states of Arkansas, Louisiana and Kansas, and portions of Mississippi, Missouri, New Mexico and Texas.	38 member systems
WSCC	**Western States Coordinating Council**, serving Arizona, California, Colorado, Idaho, Nevada, Oregon, Washington and Wyoming, and parts of Montana, New Mexico, South Dakota and Texas in the U.S. and Alberta and British Columbia in Canada.	48 member systems and 14 affiliates

Map shows inter-regional bulk power transfer capabilities. Arrows indicate the value and direction of incremental non-simultaneous transfer capabilities from reliability-council region to region, after normal base load transfers have been accounted for. These values represent the capacity available for bulk power transfer under emergency conditions, while maintaining ratings and voltages within at least emergency limits.



'84 Summer peaks no threat

As humid summer temperatures oozed across much of the U.S. in early-August, utility leaders expressed confidence that summer peak demands would impose no major threat to reliable electric service.

Conversations with representatives and staff members of regional coordination councils indicated that there was little concern over utilities' abilities to meet prospective 1984 peak demands. Barring an extremely broad, late severe heat storm and major operating problems with prime base load stations, high regional reserve margins and strong transmission networks promise continued uninterrupted service.

Representatives of regional coordinating councils were careful to point out that last summer's peak demand in many areas was heavily influenced by unusually hot weather atop the healthy economic recovery. While industrial activity still continues at a high level this year, temperatures through mid-August were generally less severe than during the summer of 1983 and only minor local difficulties have been reported.

Summer margin of 31%

U.S. generating capacity available

Continued on page 23

Power pooling . . . from page 15

for service at the beginning of the summer stood at about 557,100 MW, with a reserve margin of about 36 percent. To this has been added some 6500-MW of new capacity, plus the return of units that had been down for maintenance, bringing total generating capacity to 575,834 MW to meet the estimated non-coincident summer peak demand of 439,104 MW. This provides a national reserve margin of 31 percent. The range of margins for regional coordination councils runs from a low of 21.6 percent for the MAIN utilities to a high of 37.8 percent for the WSCC.

In addition, as mentioned above, transmission interconnections add a further safety margin, even if their ability to withstand contingencies may be reduced to some degree by base-load transfers.

The U.S. continues to be broken into three essentially independent networks. The eastern one-third of the nation, including the seven (of nine) regional coordination councils operating in the states east of the Rocky Mountains, except Texas, are well interconnected with networks of EHV and UHV transmission systems and operate on a totally coordinated basis. Western utilities, represented by the Western States Coordinating Council (WSCC), operate on a parallel basis with the east but maintain only weak ties to the east. The majority of Texas utilities, represented by the Electric Reliability Council of Texas (ERCOT), continue to operate independent of the rest of the nation, with only normally-open emergency ties across statelines.

Following is a summary of regional projections for the summer of 1984:

ECAR Projected '84 summer peak was below that of 1983 and the reserve margin was expected to be about 29.5 percent. Simulation studies of heavy power transfers into and through various parts of the area support the regional council's conclusions of power supply adequacy.

ERCOT With operable resources of nearly 46,000 MW and a strong bulk power transmission network to meet the area's expected peak demand of 36,800 MW, up 5.3 per cent from 1983, no major problems were anticipated.

MAAC With 1475 MW of capacity imports scheduled from ECAR over the summer and a new generating station (Brandon Shores) on-line, MAAC's anticipated summer reserve margin was 24.4 percent. Because of the cost differential between oil-fired generation in MAAC's eastern area and coal-fired generation in MAAC's western area, and availability of coal-based electricity from ECAR, MAAC is typically importing around 3000 MW daily from systems to the west.

MAIN MAIN experienced an exceptionally high summer peak last year and did not expect to face it again in 1984. With a reserve of 21.6 percent and heavy interregional transmission ties, no regional power supply problems had been encountered by mid-August.

MAPP With the 450-MW Antelope Valley coal-fired station on-line, utilities in MAPP enjoyed a reserve margin of 33.6 percent to meet its expected summer peak demand of 21,176 MW, up more than 3 percent from 1983. No real problems as of the middle of August.

NPCC U.S. members of NPCC entered the summer facing the possibility of a temporary shortfall of generation in New England, but with sufficient backup from New York and from Canadian members to meet contingencies.

SERC No capacity or transmission problems were anticipated in the light of reserve margins of about 32 percent and adequate transmission capacity.

SPP No problem with either generating or transmission capacity was encountered through mid-August.

WSCC Transmission limitations and the direction of power flow between various parts of the doughnut-shaped system severely restrict the transfer of economic non-oil and non-gas generation. However, council projections indicated generally adequate bulk power supplies. Interconnections to the east are small capacity and of little backup value in the event of an emergency of any significance.

Grand jury indicts former TMI worker

HARRISBURG, PA—James Floyd, a former supervisor of operations at Three Mile Island Unit 2, was indicted in June by a federal grand jury on four counts of making false statements, said U.S. attorney David D. Queen.

Floyd, 47, of Elizabethtown, PA, was the superior of all reactor operators at unit 2 from its start up through August 1979. He left Metropolitan Edison Company in April 1983.

The indictment charges Floyd with getting another licensed reactor operator to complete portions of a written requalification examination he was taking in 1979. Floyd then took the exam and submitted it as his own, charged the indictment.

In November 1979, Floyd applied for reissuance of his senior reactor operator license and stated that he had successfully completed the requalification program. The indictment charged Floyd with submitting false statements to the Nuclear Regulatory Commission.

Queen said that if convicted, Floyd could face five years in prison and/or a $10,000 fine on each of the counts.

Metropolitan Edison had pleaded guilty in March to one count of operating TMI-2 with an inaccurate and unreliable water inventory testing procedure. In a plea bargain struck with Queen, the utility pleaded no contest to six charges and four others were dropped. (See *EL&P* April 1984).

WE WELD
65 YEARS OF KNOWHOW
INTO EVERY ASSEMBLY
WE MAKE

Whether you need to get a boiler back on line fast, or are planning to retrofit for improved reliability and efficiency, it's reassuring to depend on Boiler Tube Company – the boiler fabrication specialists that have returned all types of boilers to service all across the country.

Complete Fabricating Capabilities. *With state-of-the-art production capability, modern manufacturing and testing facilities, plus two million feet of replacement tubing on hand, we're geared for large fabrications and fast turnaround. We stock a full range of carbon, alloy and stainless pressure tubing, in standard and heavy wall specifications, so chances are we can meet your needs direct from inventory.*

Performance-Proven Expertise. *Boiler Tube Company tube bending specialists and expert welders qualified to meet ASME Code standards have been applying first-hand experience to boiler outages since 1918. And that means, no matter what the problem, these fabrication professionals have probably already seen it – and solved it at just the right price.*

Fast, Economical Replacement. *Whether you anticipate complete retubing or piecemeal replacement, request a bid from the boiler fabrication experts with the nationwide reputation for fast response, economy and product reliability. We guarantee our price quotation won't leave you cold. Call or write today for additional information or literature.*

BOILER TUBE COMPANY
of America

P.O. Drawer 517, Lyman, SC 29365
Call Toll Free: (800) 845-3052 or Phone (803) 439-4488
Telex: 57-0307
Box 151, McKees Rocks, PA 15136
Call Toll Free: (800) 245-4456; in Pennsylvania: (800) 892-7071
Telex: 86-6173

© 1983 Boiler Tube Company

Inquire R.S. 8

Cogeneration . . . from page 19

ing in the thousands of dollars per kilowatt—cogeneration opportunities in these regions are plums ripe for the picking. "The big motivation here," notes FERC's Liles, taking the developers' perspective, "is not in selling power back to the utilities at avoided cost, but rather using the power yourself and backing out of that expensive retail service."

"It's no accident," he added, "...that commercial establishments on Long Island are looking at cogeneration of all types because Long Island Lighting with the Shoreham plant is now facing a very large increase in retail rates.

"I think that's where the action is," Liles concluded.

Developers must be marketers

After advising a group of potential cogeneration developers to search for utility service areas that had "unfavorable economics," Darrell A. Smith, principal attorney at Putnam, Hayes & Bartlett, offered, "There are some very significant opportunities here."

Nuclear power plant rate shock, he said, can be the localized equivalent of the 1978-79 energy crisis. This will lead a lot of persons to start thinking about how *not* to deal with their local utility.

"It has long been believed that the real costs of nuclear power were decreasing, but on-going real costs of new nuclear plants are increasing," Smith said.

The San Francisco attorney, addressing potential cogeneration developers at a recent conference sponsored by [illegible] Energy Bureau, said that unlike the earlier energy crisis, which was driven by increasing fuel prices, the rate shock crisis is driven by increasing capital costs.

"This is a very significant difference," he said.

Smith, who has had, among other jobs, positions of project manager at Pacific Gas & Electric and a fuel allocation analyst at the former Federal Energy Administration, explained that the difference works to the advantage of the cogenerator at the expense of the electric company. This is so, he said, because whereas increased fuel costs have added to the cogenerator's cost, increased capital costs do not, in a relative sense.

Recalling that many forecasters foresee all types of industrial self-generation decreasing in the future, Smith urged his listeners to market their electricity by positioning themselves to meet their customers needs. While "customers" here can be those industrial companies that contract with a third party for electricity and/or thermal energy, they can also be existing or potential utility ratepayers, thereby exploiting the fact that cogenerators and small power producers can sell their electricity on the retail market.

PURPA neither authorizes nor denies retail sales, notes FERC's James Liles, for this is primarily a matter of state law. Thus, qualifying status of a facility is not jeopardized by such sales. "It's not where the power goes [that's of interest], but how it is produced," Liles said.

Electric utility impacts

While it is speculative for analysts to project cogeneration capacity to the year 2000, it is even more risky to estimate the impact of this growth on utility planning, service, and economics. Some analysts, like Liles, believe that cogeneration facilities constructed to meet the steam and electricity needs of large industrial and commercial firms could eliminate large blocks of new electric company load. In addition, to the extent a cogenerator has excess electricity to sell, the utility will have even more of its energy production requirement offset as it purchases that electricity at its avoided cost.

But Glen H. Lovin, president of the International Cogeneration Society, doesn't think electric companies have all that much to worry about here. Even given the more liberal cogeneration growth estimates of 44,000 MW by the end of the century (see box), Lovin says, "...Only 3,000 [industrial] plants with the highest potential for conversion [to cogeneration] are included in the projected potential of 44,000 MW and these plants are spread out across the United States."

Speaking recently at a roundtable discussion with the editors of *Power Engineering* magazine, he added, "If they all converted to cogeneration systems, we would not expect any great impact on the local utility companies."

Other industry observers are less sanguine, however. Writing in the most recent issue of *Energy Business*, a publication of Ebasco Services Inc., Louis J. Sas and Irving Fruchtman note that over the next 10 years, 25,000 MW of cogeneration and small power production will be added to the U.S. grid. The authors warn that unless electric utilities take marketing action this capacity will be developed by others.

"As leaders in the energy supply business, electric utilities must protect existing markets and respond to new opportunities," the Ebasco authors write. "With continued government encouragement, cogeneration and small hydropower facilities will represent 15 percent of new generating capacity because of their rapid payback and high profit margins. Utilities should form partnerships, joint ventures, or non-regulated subsidiaries and aggressively develop small energy projects to maintain their influence in the management of electric energy."

General Electric estimates that as much as 39,000 MW of cogeneration capacity could be on line by the end of the century. "This would suggest that we're looking at a major change in the method of producing electricity and steam in this country...," says John Wing, general manager of the company's cogeneration applications department.

Wing, who served as conference moderator at a GE-sponsored cogeneration meeting that was attended by more than 60 major U.S. companies last May added that "It signals a shift in the ownership and location of energy conversion facilities, with implications for, and new relationships with the utility industry that has traditionally performed the task."

But while General Electric is aggressively courting industrial firms in the hope of selling them cogeneration facilities, at least one electric utility has taken a bold step to get involved in a small power production project itself. The move is seen as having potentially critical ramifications on a larger scale for the electric utility industry.

Tucson Electric Power, through its wholly-owned subsidiary Rincon Investing Company, has come up with two-thirds of the capital necessary to construct a nominal 11 megawatt plant that will use biomass in the form of waste wood as its primary energy source. Joining in partnership with Ultrapower 3, Inc., a private company, Rincon, as an "electric utility," is restricted from owning more than 50 percent of the facility under FERC rules.

Nevertheless, Rincon will make an initial capital contribution of $5 million to the partnership, while Ultrapower 3, Inc. will make a $2.5 million contribution. The joint agreement provides that each party will have a 50 percent interest in the venture profits and losses. Management decisions are to be made by a policy committee with each partner equally represented.

What is noteworthy about this case is that FERC has concluded that the Ultrapower 3 facility meets the criteria for qualifying small power production facilities.

According to FERC rules, a cogeneration or small power production facility is considered to be owned by a person primarily engaged in the generation or sale of electric power if more than 50 percent of the equity interest in the facility is held by an electric utility.

What the commission had to decide in this case was whether the entitlement to profits, losses, and surplus determined the equity interest in the partnership, or whether such interest was set by the contribution of capital to the venture and the entitlement to the original contributions upon liquidation of the company.

Stating that the initial contribution of capital by the partners may be more properly viewed as debt than equity, and declaring further that this capital contribution conveyed no management rights nor did it influence the distribution of profits, the April 19, 1984 FERC order decided that Rincon had no more than a 50 percent equity interest in Ultrapower 3 and that, therefore, the commission's "qualified facility" ownership rules were met.

"The partners do not individually own any identifiable assets," the order reads. "There are no shares of stock outstanding. Under these circumstances we have looked to the stream of benefits from the venture to determine the equity interest of the partners."

To the extent this reasoning is applicable on a broader scale, it opens the door to fuller electric utility participation in the financing and construction of cogeneration and small power production facilities. Although FERC's James Liles allows there may now be an incentive for electric utilities to contemplate providing 100 percent of the capital cost of a new cogeneration or small power production facility, he quickly adds that the precedent in the Ultrapower 3 case is very narrow, and residual questions linger on the broader applicability of the facts of this case.

The commission itself seemed to presage this view when it wrote in the April Ultrapower 3 order, "We would be particularly concerned if the utility were to receive any special advantages as a result of the partnership, such as service contracts with favorable terms or the right to loan money to the partnership at non-commercial interest rates."

The interpretation of the Ultrapower 3 case as an end run around PURPA and FERC rules in an attempt to avoid the 50 percent utility ownership limitation has to be viewed critically. Clearly, there does not appear to be much enthusiasm these days on the part of electric companies to revoke the 50 percent ownership limitation.

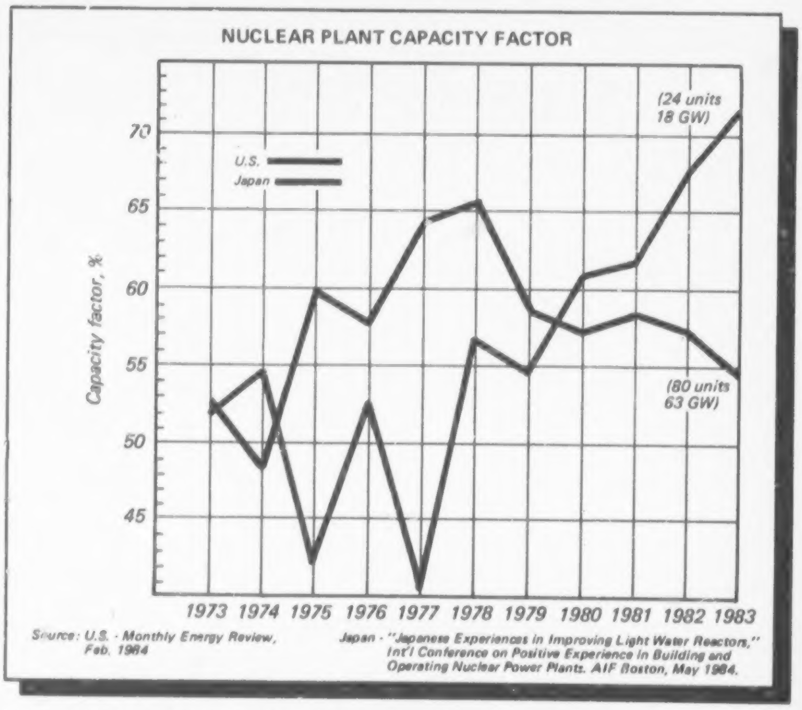
According to a legislative aide at the House Subcommittee on Energy Conservation and Power, Subcommittee Chairman Richard Ottinger earlier had made it known that he would be open to utility petitions aimed at rescinding the 50 percent ownership rule. There was, however, "not a peep [from utilities] during the whole Congress," the aide said.

It makes us conclude, he added, that either electric utilities are not very interested in this, or they have some larger plan to go after PURPA after Ottinger is gone.

Ottinger has announced he would not seek reelection this fall.

Correction

Japanese nuclear plant CF rises



Source: U.S. - Monthly Energy Review, Feb. 1984

Japan - "Japanese Experiences in Improving Light Water Reactors," Int'l Conference on Positive Experience in Building and Operating Nuclear Power Plants. AIF Boston, May 1984.

The corrected graph of Japanese and U.S. nuclear plant capacity factors shows that while U.S. performance has been declining over the past 5 years Japanese plants have improved tremendously. The original graph that accompanied a feature article on capacity factor improvement efforts in the August issue of *EL&P* (page 26) omitted the line showing the impressive turnaround in Japanese nuclear plant performance.

Nuclear PACs carry clout, says Critical Mass

WASHINGTON, D.C.—Public Citizen's Critical Mass Energy Project, the Ralph Nader safe energy advocacy group, says there is a "strong correlation" between congressional voting records and the amount of money Congress members receive from nuclear political action committees (PACs).

A recent Critical Mass study found that House members who always voted for the nuclear industry's position on key issues received about four times as much money as those who consistently voted against the industry.

"During the 1981-82 and 1983-84 election cycles," said the study, "80 utilities and nuclear-involved corporations gave $3,355,410 to congressional members who, more often than not, voted for the industry's position on key legislation."

Sheila Mayberry, the study's author, picked five Senate and House nuclear-related votes in 1982 and 1983 to examine. They include: the question of further Clinch River Breeder funding; an amendment that would give states the right to refuse a high-level radioactive waste burial site; an amendment to ban the use of commercial spent fuel for the production of nuclear weapons; stricter requirements on nuclear exports; and the construction work in progress bill.

Mayberry compiled the data in the study from reports submitted to the Federal Election Commission. Under federal law, businesses, trade unions and other organizations may not contribute money directly to candidates. They are allowed to set up PACs, which may contribute up to $5,000 per candidate per election. The primary and the general elections each count separately.

Many of the utilities and corporations examined in the study, said Mayberry, have more than one PAC.

Mayberry said congressional members received contributions from 44 utility and 36 nuclear-involved corporate PACs. The utilities have investments in nuclear plants and the corporations are suppliers of goods and services to the industry.

Largest contributors

The study found that utility PACs gave $880,165 between 1981 and 1983. The largest contributors were Texas Utilities ($83,300), Consumers Power ($67,265) and Florida Power & Light ($66,200).

Nuclear-involved corporations, said the study, gave congressional members $2,475,245 during the same time frame. The largest corporate donors were General Electric ($243,100), Fluor Corporation ($212,900) and Rockwell International ($204,800).

"The nuclear industry is losing the support of the American public and the financial resources of Wall Street," said Critical Mass Director Michael Totten, so the industry appears to be offsetting this erosion of confidence with efforts to secure taxpayers' funds by investing campaign contributions in members of Congress."

House members who received more than $20,000 in nuclear PAC contributions were more than three times as likely to vote in favor of the nuclear industry's position than representatives that received no money, said Critical Mass.

While in the Senate, members who accepted more than $20,000 were more than twice as likely to vote along industry lines than senators not receiving PAC money.

Critical Mass said six of the ten largest Senate recipients sit on committees that have jurisdiction over nuclear-related legislation. The group said Sen. James McClure (R-ID), who serves as chairman of the energy and natural resources committee, received $46,000 in PAC money and voted against the nuclear industry only 20 percent of the time.

The study found that the largest concentration of industry PAC money in the House went to committee members. It said they received almost $1.5 million in contributions.

Among individual members who consistently voted for the nuclear industry's position were Sen. Bennett Johnston (D-LA), who received $56,815 in PAC money, and Sen. McClure, who accepted $46,775.

The study also pointed out that some congressional members voted against the industry's position even though they received a substantial amount of PAC money.

TOP 20 PAC CONTRIBUTIONS BY NUCLEAR UTILITIES
(1981-82 and 1983-84 Election Cycles)

Utility	Total	Utility	Total
1. Texas Utilities Co.	$83,300	11. Gulf States Utilities	$27,450
2. Consumers Power Company	67,265	12. General Public Utilities	25,530
3. Florida Power and Light	66,200	13. American Electric	23,175
4. Southern California Edison	63,700	14. Alabama Power Co.	22,960
5. Middle South Utilities	57,425	15. Virginia Electric Power Co.	22,050
6. Georgia Power Co.	38,485	16. Consolidated Edison	19,750
7. Pacific Power and Light	38,255	17. Commonwealth Edison	19,825
8. Detroit Edison	34,250	18. San Diego Gas and Electric	17,725
9. Carolina Power and Light	32,275	19. Boston Edison	17,703
10. Baltimore Gas & Electric	29,950	20. Puget Sound Power and Light	17,425
		TOTAL	$724,698

Source: Public Citizen's Critical Energy Mass Project

THE TOP TEN RECIPIENTS OF NUCLEAR PAC CONTRIBUTIONS

Top Ten Recipients in the House of Representatives

Representative	Total PAC Money Received	Percentage of Votes Against the Nuclear Industry
Gramm, P (R-TX)	$45,825	0%
Michel, H (R-IL)	33,575	20
Rostenkowski, D (D-IL)	31,300	80
Chappell, B (D-FL)	28,000	20
Fuqua, D (D-FL)	27,000	40
Fields, J (R-TX)	25,125	20
Jones, J (D-OK)	22,300	40
Smith, R (R-OR)	21,958	33
Hunter, D (R-CA)	21,390	20
Shelby, R (D-AL)	20,785	20

Top Ten Recipients in the Senate

Representative	Total PAC Money Received	Percentage of Votes Against the Nuclear Industry
Wilson, P (R-CA)	$82,815	50%
Johnston, J (D-LA)	56,800	20
Hatch, O (R-UT)	48,696	60
McClure, J (R-ID)	46,775	20
Bentsen, L (D-TX)	45,118	20
Tower, J (D-TX)	39,800	0
Durenberger, D (R-MN)	36,200	40
Evans, D (R-WA)	34,050	0
Warner, J (R-VA)	32,975	60
Wallop, M (R-WY)	32,750	20

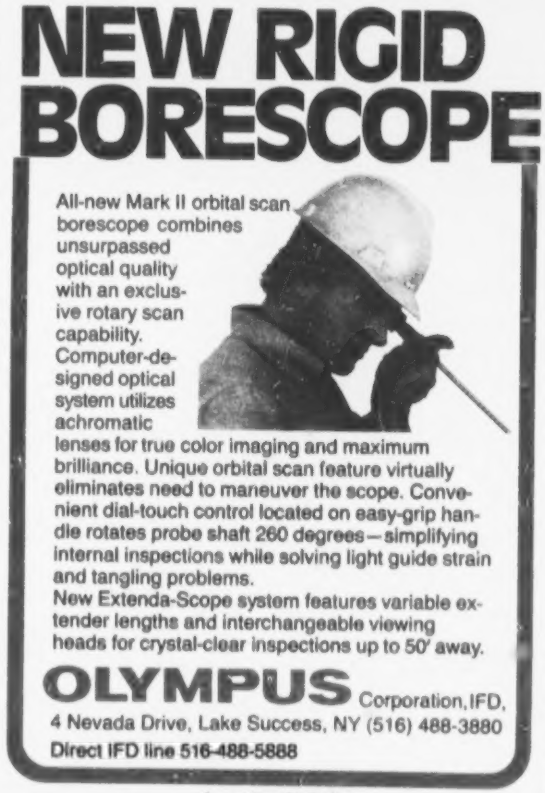
Source: Public Citizen's Critical Energy Mass Project

NEW FLEXIBLE FIBERSCOPES

Inspect deep inside turbine equipment for defects on liners, nozzles, and rotor blades. Now available in lengths up to 20', new industrial fiberscopes feature fully articulated tips which move up, down, left, and right. Choice of 7 interchangeable tip adapters allow inspectors to first scan large areas and then zero-in on specific defects for sharp, close-up views. Unique remote control handle manipulates scope tip angulation for greater visual freedom. Inclusion of two light guide windows in each tip provides more even illumination of viewing area for enhanced visual clarity and resolution.

OLYMPUS Corporation, IFD,
4 Nevada Drive, Lake Success, NY (516) 488-3880
Direct IFD line 516-488-5888

Inquire R.S. 53



NEW RIGID BORESCOPE

All-new Mark II orbital scan borescope combines unsurpassed optical quality with an exclusive rotary scan capability. Computer-designed optical system utilizes achromatic lenses for true color imaging and maximum brilliance. Unique orbital scan feature virtually eliminates need to maneuver the scope. Convenient dial-touch control located on easy-grip handle rotates probe shaft 260 degrees—simplifying internal inspections while solving light guide strain and tangling problems.
New Extenda-Scope system features variable extender lengths and interchangeable viewing heads for crystal-clear inspections up to 50' away.

OLYMPUS Corporation, IFD,
4 Nevada Drive, Lake Success, NY (516) 488-3880
Direct IFD line 516-488-5888

Inquire R.S. 54

EXPLOSION-PROOF LIGHT SOURCE

All-new UL Listed AXL-100 Explosion-Proof Light Source permits extended, safe fiberscope and borescope inspection in hazardous areas without overheating. Designed to run at a constant, safe temperature for hours of uninterrupted inspection, AXL-100 uses 12-volt, 100-watt focused halogen lamp for maximum light output with minimum heat.
This durably-built unit illuminates the inspection area for unsurpassed brilliance and clarity.
For the first time, internal visual inspections are now possible in areas previously considered too dangerous for use with conventional light sources.

For more information

OLYMPUS Corporation, IFD,
4 Nevada Drive, Lake Success, NY (516) 488-3880
Direct IFD l[illegible] 516-488-5888

Inquire R.S. 55

NOTE

ONLY THE FOLLOWING PAGES OF THIS

PUBLICATION HAVE BEEN FILMED

Cov. 1, p. 2, 4.

C8650-4

Volume 62, Number 10
October 1984

09035 1984301 W 3 2005
SUITE 800 COPY # 1
CONGRESSIONAL INFC SERVIC D
4520 EAST WEST HWY STE 800
BETHESDA MD 20814

BEST AVAILABLE COPY

Electric Light & Power

THE NEWS MAGAZINE OF ELECTRIC UTILITY MANAGEMENT AND TECHNOLOGY

© TECHNICAL PUBLISHING

WPPSS signs accord with BPA to forestall default

Rep. Dingell hits further BPA 'entanglements' with WPPSS

PORTLAND, OR—The Washington Public Power Supply System and the Bonneville Power Administration have entered into an agreement to possibly forestall supply system bankruptcy and maintain the three remaining nuclear units as viable generating resources.

The accord is an attempt to keep some type of institutional relationship alive between the two parties in the event that the so-called net billing agreements, now under legal attack in the courts, are rendered invalid.

The Ninth Circuit Court for several months has been considering a suit questioning the legality of BPA's net billing program. If it rules that the Northwest utility participants had no authority to enter into net billing agreements with BPA, the supply system would be pushed into a nosedive toward default on $6 billion invested in the three nuclear units.

Under such a court ruling, with the utility participants no longer obligated to meet their contractual stipulations, WPPSS would quickly run out of money, says WPPSS spokesman John Britton. It would not be able to continue to operate WNP-2, which just recently became operational, nor would it be able to meet its debt obligations for WNP-1 and WNP-3, which currently are in "mothballs."

The "assignment agreements" are an attempt to circumvent these events.

The attack on the net billing agreements is being spearheaded by the Springfield (Oregon) Utility Board. With other plantiffs, the board is arguing before the courts that Northwest utilities had no authority to enter into the net billing agreements and therefore they are not bound to continue their obligations under them.

This is essentially the same argument that was accepted by the Washington and Oregon courts with respect to WPPSS nuclear units 4 and 5, and that precipitated supply system default on over $2 billion in outstanding securities.

In the present case, however, WPPSS and BPA have one strong element in their favor: the validity of the net billing agreements with respect to nuclear units 1, 2, and 3 was upheld last year in federal district court. The effort to establish assignment agreements is viewed as a contingency plan in the event the Ninth Circuit Court invalidates the existing billing accords.

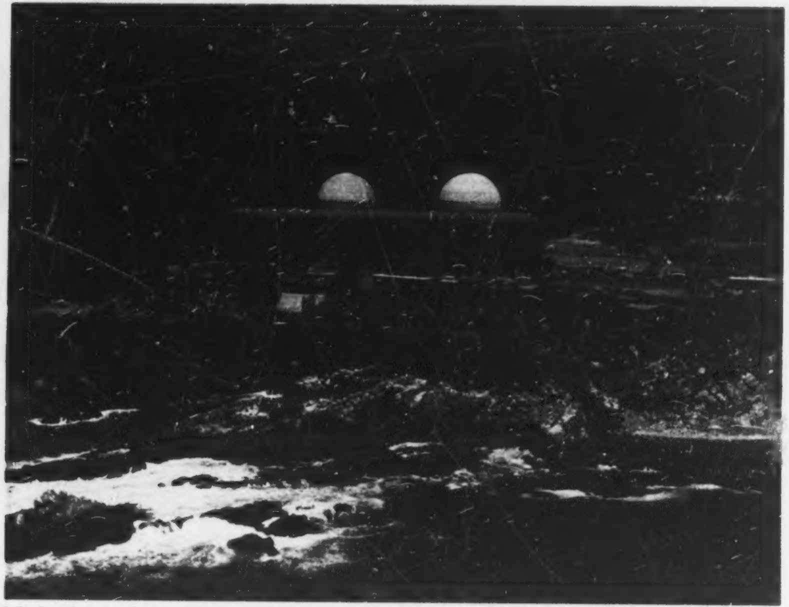
'Net billings' are complex

The net billing agreements are complex arrangements that institutionally relate WPPSS, BPA, and over 100 Northwest utility participants in the construction, operation, and power distribution of WNP-1, WNP-2, and WNP-3. Under the agreements, each utility purchases a share of each plant from the supply system, which, as a joint operating agency, assumes responsibility for financing and constructing the plants. Each utility would then assign its allocated output to BPA.

By blending the costs of this new,

Continued on page 10

Diablo start-up blocked



A federal appeals court halted operation of Pacific Gas & Electric Company's $5.1 billion Diablo Canyon nuclear plant on August 17, just hours after its full power license went into effect. The halt will last at least until November, when the appeals court will hold a hearing to review claims of the plant's opponents. In the meantime, PG&E will be allowed to operate the plant at low power testing levels. The utility said it was disappointed with the ruling by the U.S. Court of Appeals for the District of Columbia and would file an appeal. Joel Reynolds, a lawyer for the Center for Law in the Public Interest, representing groups opposing the plant, said the court's action was an indication of all the claims made by the group before the Nuclear Regulatory Commission in the last 15 years. PG&E also asked the U.S. Supreme Court to hear the case, but the Court refused. PG&E Chairman and Chief Executive Officer Frederick W. Mielke Jr. said legal and other delays have caused weekly operating costs of $16.1 million. Mielke said the utility has asked the federal appeals court to speed up hearings on the injunction.

PUC 'bias' delays PSNH financing

MANCHESTER, NH—The New Hampshire Supreme Court, ruling that the chairman of the state's Public Utilities Commission made biased public statements regarding the Seabrook nuclear plant and Public Service of New Hampshire, has overturned commission approval of the utility's $425 million financing plan.

Public Service of New Hampshire had been poised to issue securities in order to generate needed cash, but the court's ruling temporarily has thwarted the plan, leaving the company in an increasingly difficult cash flow situation.

On August 28, the New Hampshire Public Utilities Commission approved PSNH's proposal to issue up to $425 million in securities to cover the company's cash needs over the next two years. However, responding to an appeal by the Seacoast Anti-pollution League, the New Hampshire Supreme Court two days later suspended the approval, pending review of two contentions put forward by intervenors.

The league claimed that because of remarks made in a recent speech, the PUC chairman should have disqualified himself from participating in the agency's decision on the proposed PSNH financing plan. The league further claimed that the PUC unjustly narrowed the scope of the financing plan review.

On September 7, the state's high court agreed that the speech at the very least gave the appearance of bias and said that although the PUC's nar-

Continued on page 11

Broad-based contributions aren't political, EEI says

Dan Utroska
Associate Editor

Investor-owned electric companies that are dues-paying members of the Edison Electric Institute (EEI) are indirectly supporting a host of local and national organizations such as the Business-Industry Political Action Committee, the Chamber of Commerce of the United States, the Committee to Elect Democratic Governors, the Congressional Black Caucus Foundation, and the Congressional Hispanic Caucus.

Details of the wide-ranging financial support given to these groups by EEI is contained in a June 29, 1984 document prepared by the institute in response to questions posed by the National Association of Regulatory Utility Commissioners (NARUC) as part of the association's on-going investigation of EEI revenues and expenditures. *EL&P* has obtained a copy of this report which, together with testimony of an EEI official in a state rate proceeding, reveals that electricity consumers, through utility dues to EEI, are contributing to a variety of groups and organizations that may be engaged in political activities and lobbying.

Over a five-year period from 1979 to 1983, EEI contributed $3.5 million in cash to such organizations. This does not include "in-kind" (e.g., staff office space, overhead, etc.) contributions to these same groups. As a means of reference, $3.5 million is 3.8 percent of EEI's total dues spent over the period, an institute spokesman said.

The remaining EEI dues expenditures go for collecting, developing, analyzing, and disseminating information on the generation, sale and use of electricity, the EEI spokesman said. This includes training programs for member companies, data collection and the composition of studies available to member companies and the public. It also includes analyses of pending legislation for member companies.

Since EEI revealed the extent of its donations to these groups and organizations, questions are being raised as to what is and what is not a political contribution. According to federal law, it is illegal for a corporation to make a contribution or expenditure in connection with any federal election.

EEI maintains that none of the contributions detailed in its June 29, 1984 response to NARUC violate definitions as described in federal election laws.

Also at issue now is that fact that EEI's detailed list of organizational expenditures shows that, whether political or not, EEI is making dona-

Continued on page 19

Foreign Power Briefs

- **The People's Republic of China** and the United States have signed a major hydropower agreement. U.S. Secretary of the Interior William Clark said the agreement, signed on August 3, calls for the Bureau of Reclamation to provide technical and consulting services over the next five years in the design of the 13,000 MW Three Gorges Project on the Yangtse River. China will be responsible for the construction and operation of the dam, as well as reimbursement for all U.S. technical and consulting services. When completed, the Three Gorges Project will be almost as high as the Hoover Dam and more than a thousand feet longer than the 10,000 MW Grand Coulee Dam. Interior Secretary Clark said, "We are pleased to be entering this landmark agreement with the People's Republic of China. We expect both countries to derive benefits from this cooperative effort."

- **Mitsubishi Heavy Industries Ltd., of Tokyo,** has won a contract to supply a turbine generator for Pacific Gas & Electric Company's proposed geothermal plant at The Geysers site, near San Francisco. PG&E said it will pay approximately $10 million for the generator, which is expected to be delivered in March 1987. The utility hopes to begin construction of the $216 million, 151,000-kW plant in May 1985 and start operation in September 1988.

- **Mitsubishi and Westinghouse Electric Corporation** have extended a technology transfer agreement that will enable the Japanese concern to make use of Westinghouse innovations in commercial nuclear power technology for generating electricity through 1996. The new agreement means Mitsubishi will have access to technology earlier in the development process than under earlier agreements, said Westinghouse. In return, the American company will receive Mitsubishi technology, including research and development information and operating performance data from Japanese nuclear plants.

- **Sweden's** Studsvik Energiteknik has sold a license for its circulating fluidized bed combustor to Babcock & Wilcox USA. Studsvik said its combustor has excellent fuel flexibility, and low carbon monoxide, nitrous oxide and hydrocarbons emissions.

- **Deutsches Atomforum**, a West German nuclear industry group, reports that atomic power accounted for 21 percent of the electricity fed into the country's power grid in 1983, unchanged from 1982. The group said nuclear plants generated 65.9 billion killowatthours of electricity last year, up five percent from 1982.

- **The Ismailia Power Station** in Abu Sultan, Egypt, will get a fourth steam generator. Foster Wheeler Energy Corporation said it has received an $11 million contract from General Electric Company's International Projects Department to design and fabricate the steam generator for completion in 1986. Capacity of the generator will be 164 MW.

- **Korea Power Engineering Company (KOPEC)** has awarded a contract to Burns and Roe, Inc., for consulting services for two new nuclear plants in South Korea. The new units, Korea-11 and -12, will be in the 900 MW range. The site is undetermined. Burns and Roe said it will provide engineering and design services, including advisory assistance relating to contracts with potential suppliers of the two nuclear units.

In This Issue

The likely energy policies of Ronald Reagan and Walter Mondale are examined in a special election preview. 3
Editorial 4
Calendar 13
An aging coal-fired power plant was modernized with a new distributed digital control system. **G** 16
PCB transformers are being replaced by many utilities even though there is no formal requirement, yet. **T/D** 26
A sulfur-dioxide scrubber additive has improved performance in several demonstrations but is slow to catch on with utilities. **G** 35
Readers' Service 39
New Products 43
New Literature 45
Regulatory Review 47
Management Methods 50

EL&P readers whose responsibilities include both Generation and Transmission/Distribution receive both technology sections. Other readers receive the technology section that applies to their respective area of responsibility. The Generation edition is indicated by a single dot (•) in the upper right corner of page 1; the T/D edition carries two dots (• •). All readers receive EL&P's industry news section

TVA cancels four units

KNOXVILLE, TN—Despite an investment of $2.7 billion, the Tennessee Valley Authority cancelled four nuclear reactors in late August.

The TVA board accepted a staff recommendation to cancel the two-unit Hartsville A project and the two-unit Yellow Creek plant. Construction had been deferred on all four units in 1982.

Between 1966 and 1975, the agency approved plans to build 17 nuclear units. TVA now has cancelled eight nuclear units. Four are still under construction and five are operating.

TVA Director John B. Waters said, "The Tennessee Valley Authority does not need the two Hartsville and the two Yellow Creek nuclear units." He said the units are unaffordable.

Sufficient capacity

Waters said he is confident that TVA has sufficient capacity to "get this region comfortably through the mid-1990s."

When first announced in 1974, TVA estimated it would take $800 million to complete Hartsville A. The most recent estimate to finish the plant was $5 billion. Hartsville A-1 was 44 percent finished and unit 2 was 34 percent complete.

Yellow Creek was first announced in 1975 at a cost of $1.9 billion. TVA recently estimated it would cost $9.6 billion to finish Yellow Creek.

Said Waters, "...the total cost of the entire TVA power system now in operation is less than $10 billion. That says a lot in itself."

Yellow Creek-1 was 35 percent complete and unit 2 was 34 percent finished.

Hugh Parris, TVA manager of power, said in a staff review of the plants that it was in the best interest of the ratepayers to cancel the units.

Too expensive

"In conclusion," wrote Parris, "our study shows that the increasing construction and operating costs of nuclear plants have simply made them too expensive to consider for our future generation requirements."

TVA said that over the next 11 years it will write-off the more than $4 billion spent on the eight cancelled nuclear units.

"The truth of the matter is that, in the '60s and early '70s, the need for new capacity was overestimated," Waters said at the August board meeting, "the cost for new plants was underestimated, and the price the public could and would pay for electricity was misunderstood."

ASLB authorizes Limerick license

PHILADELPHIA—The NRC's Atomic Safety and Licensing Board (ASLB) has authorized the commission to grant a low-power testing license to Philadelphia Electric's Limerick station.

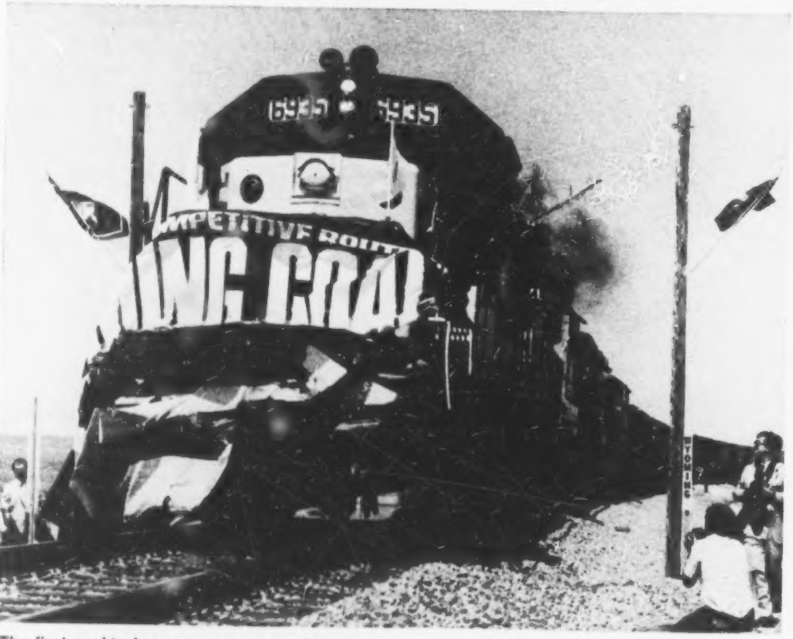
The three-member board said, "Philadelphia Electric Company has fully met its burden of proof on each of the contentions. There is reasonable assurance that the Limerick Generating Station, Units 1 and 2, can be operated without endangering the health and safety of the public, and further that all requirements applicable to these issues under the National Environmental Policy Act have been met."

PE Senior Vice President for Nuclear Power Vincent S. Boyer said, "We at PE do not regard this decision as indicating our job is finished but as an important milestone in the continuing plan to place Limerick Unit 1 into commercial operation to serve our customers."

Fuel loading

The utility expected to load fuel in September. Limerick 1 is expected to enter commercial operation in Spring 1985. Construction on unit 2 was suspended pending commercial operation of unit 1.

Powder River line opens



The first coal train to move on a new $370 million, 107-mile coal route serving Wyoming's Powder River Basin bursts through a banner during August ceremonies at the Wyoming-Nebraska state line. Jointly financed and built by the Chicago & Northwestern Transportation Co. and the Union Pacific System, the new track is expected to increase competition and reduce coal rates for some utilities. The line from Morill, NB to Shawnee, WY connects the rail companies with a line into the Powder River Basin that was built by the Burlington Northern Railroad. C&NW had paid BN to share the line. C&NW and UP say they expect to be hauling more than 35 million tons of coal annually from Wyoming by 1990. (Photo by Union Pacific System)

Editorial

Canadian power imports look good now...but tomorrow?

Ratepayers in New York, New England, Michigan, the upper North Central states and the Pacific Northwest stand to realize savings in their electricity bills as the result of import contracts signed with Canadian utilities. For customers trapped in normally high-cost oil-based generation areas, the prospects seem especially attractive, at least in the short-term. But recent rapid increases in the amount of power imported...and the prospect for further substantial increases over the next five years...is cause for some concern.

In 1983, according to the Department of Energy, almost 40-billion kWh were imported into the U.S., almost solely from Canada (electricity from Mexico represented less than 1 percent of the total kWh imported). The tab for this power in 1983 amounted to about $1-billion. Moreover, DOE is estimating that imports will double by 1990. The Canadian Energy Board, however, estimates that sales to U.S. utilities could increase to 30-times the 1983 total...or $30-billion.

Short-term, there is little question but that current imports make a lot of economic sense for some utilities. Certainly as replacements for potential new high-cost capacity, Canadian kilowatthours are a bargain. Contracts with U.S. utilities also are good for the Canadians, who stand ready to build new capacity in order to serve the growing U.S. appetite for electricity. Manitoba, for example, is currently negotiating a contract with the Western Area Power Administration (WAPA) under which the Canadian utility will develop hydro facilities on the Nelson River and commit 1275 MW of capacity to WAPA for 35 years. The price for the power will be tied to what WAPA would pay for coal to fuel a now deferred power plant. The province of New Brunswick even stands ready to add new nuclear capacity to meet U.S. needs.

In New York and New England, where power costs are the highest in the nation, imports are helping to hold the price line. New York imported about 55 percent of the total electricity brought in, which provided for about 17 percent of its needs. New England imported 15 percent of the total to provide for about 6 percent of its demand for kWh, but has signed several new contracts that will push its dependency higher in future years.

DOE, according to DOE manager of Electricity Import-Export Licensing Garet A. Bornstein, is fearful that longer-term costs may not be as favorable as now. "What looks like a good deal today, we might bemoan in the long-run."

The problem he foresees is that the Northeast is heavily dependent on oil-fired generation. Where the price of imported electricity is related to avoided costs and where the avoided costs are based on oil as the base fuel, future pricing problems could arise. Should there be a disruption in the supply of oil, Bornstein says, it could produce an increase in the price of the fuel...perhaps even a doubling. That would mean, he argued, that any electricity imported under such a contract would effectively be the same as importing oil.

At the same time, Bornstein pointed out, many American utilities, in the midwest for example, have more than adequate supplies and above-normal reserves of coal- and nuclear-based capacity that could be used to economically meet the needs of the Northeast or northern-tier states. Although existing transmission capacities may be insufficient to move large incremental blocks of energy from the Midwest to the Northeast, Bornstein suggests they might be expanded and uprated for less than the cost of new Canadian transmission ties.

Moreover, strengthening transmission ties between Midwest and Northeast utilities, and removing regulatory obstacles to large-scale transfers of electricity, would allow utilities in New York and New England to buy energy from U.S. utilities that already need outlets for their excess capacity, to the mutual benefit of both buyer and seller...and their customers.

Taking advantage of low energy rates for electricity from Canada does make sense so long as the rates remain low and the amount imported remains a small portion of total demand. But long-term, potential pricing problems, to say nothing of national security issues, would seem to suggest that greater domestic cooperation and interregional transfers offer a more beneficial and dependable outlook for the future.

Robert A. Lincicome, Editor-in-Chief

Next: The Electric Utility of the Year

WE files to lower rates $8.1 million

MILWAUKEE—For the second consecutive year, Wisconsin Electric Power Company has filed a request to lower its rates with the Wisconsin Public Service Commission.

The utility asked the commission to approve a decrease in the base electric rate of $8.1 million. Previously, Wisconsin Electric lowered its rates $20.5 million.

Cost-control measures, repurchase of some of the utility's common stock, revised accounting procedures, reductions in the amount earned on funds borrowed for construction and a delay in the startup of Pleasant Prairie Unit 2 were cited by the utility as major reasons for the rate decrease request.

If approved by the PSC, the decrease would be effective January 1, 1985. According to the company, Wisconsin Electric is the only major electric utility to seek a rate reduction in each of the past two years.

WE Chairman Charles McNeer said the company's electric rates are among the lowest in the nation. He said the rates could be a factor in attracting new industries and jobs to Wisconsin.

A year ago McNeer said the utility would strive to "achieve a new era of no rate increases."

EEI sponsors renewable energy issues conference

WASHINGTON, D.C.—The Edison Electric Institute said it will join with the Renewable Energy Institute in sponsoring a conference on environmental and regulatory issues associated with renewable energy technologies.

The conference, *Utilities and Renewable Energy: Environmental and Regulatory Issues*, will be held Nov. 12-14 in Boston.

EEI said the purpose of the conference is to identify and discuss the major environmental and regulatory issues associated with the development of renewable energy technologies for electric power production.

Attention will be focused on small-scale hydro, biomass, refuse-to-energy, solar, wind, photovoltaic and cogeneration technologies.

For more information, call Richard Loughery, EEI, (202) 828-7626.

Com Ed retires Dresden

CHICAGO—Commonwealth Edison announced that it will retire its Dresden unit 1 which, when put on line in 1960, was the first privately financed nuclear plant in the world.

The utility said the 200-MW unit, shut down since 1978, is being retired because it would cost $300 million to bring it into compliance with NRC's post-TMI regulations, an "impractical" investment.

A long-planned chemical decontamination program for the reactor, the first for a large commercial reactor, was slated to be completed in late September. Following chemical cleaning Com Ed plans to mothball the unit for the useful life of the site, which includes two other units.

CEO pay lower at public utilities: new survey

NEW YORK—A new survey of 408 utilities shows that average base salaries of chief executive officers of publicly owned utilities are considerably lower than those of CEOs in investor-owned utilities.

Survey results

The Towers, Perrin, Forster & Crosby survey said CEOs of investor-owned utilities of between $50 and $200 million in revenues make $107,000 a year. CEOs in publicly-owned utilities earn $61,700.

Corrections

An article in the Oct. *EL&P* on p. 36 "PR execs say state regulator's intrude in utility affairs", incorrectly reported that public relations executives said their state regulatory commissions have always intruded into management functions. The sentence should have read, "The executives told Bogart, 15 to 2, that their state commissions have not intruded into traditional management functions in the past, but will do so increasingly in the future." *EL&P* was given incorrect information.

The special report on operations at the top 100 investor-owned electric utilities in the August, 1984 issue contained two errors. The change in oil consumption for Baltimore Gas & Electric from 1982 to 1983 included in the table on page 8 should have read -24 percent, not +24 percent. The generating capacity in the fossil category reported for Florida Power & Light in the table on page 10 should have been 8632 MW, a decline of 147 MW from the previous year, not 8186 MW, down 593 MW, according to J.R. Sullivan of FP&L's system planning department.

Electric Light & Power

EL&P. Staff

Vice President and Group Publisher
Robert J. (Duke) Kiesel
Sales Manager
Arthur L. Rice
Editor-in-Chief
Robert A. Lincicome

Editorial Staff
Robert W. Smock, Managing Editor
Dan Utroska, Associate Editor
Donald F. Minner, Jr., Assistant Editor
Dianne Wilson, Editorial Assistant
Maureen Schade, Editorial Assistant
Elisa Girard, Art Director
Circulation
Joseph J. Zaccaria, Director

Contributing Editors
William Kenworthy, Legal/Regulatory
Ted Pollock, Management
Production
Judith S. Schwabe, Regional Director
Laura Smith, Manager
Marketing Services
Margaret Shake, Promotion Manager

Research
Susan Humes, Associate Research Manager
Editorial Advisory Board
H. L. Culbreath, Tampa Electric Co.
Clayton K. Larson, Northern States Power Co.
Edward A. Myers, Jr., Southern California Edison Co.
John T. Stiefel, Stiefel Associates, Inc.

Technical Publishing
a company of
The Dun & Bradstreet Corporation
Barrington, IL 60010 • (312) 381-1640

ELECTRIC LIGHT & POWER (USPS 858-860) is published monthly. © copyright 1984, by Technical Publishing a division of Dun-Donnelley Publishing Corporation, a company of the Dun & Bradstreet Corporation—all rights reserved. John K. Abely, President; Robert L. Dickson, Executive Vice President; John R. Emery, Senior Vice President; Robert J. (Duke) Kiesel, Vice President and Group Publisher. Editorial and Executives offices: 1301 S. Grove Ave. P.O. Box 1030, Barrington, IL 60010. Phone (312)381-1840. Distributed to executives and engineers in U.S. electric utilities and consulting engineering firms. Second-class postage paid at Barrington, IL 60010 and at additional mailing office. To all others there is a subscription charge of $38 per year (U.S.) $46 (Canada), and $66 foreign, ($108 foreign air mail, as of January 1, 1985). Single copy prices $4.00 + Postage (U.S.) $5.00 + Postage (Canada), and $7 + Postage (Foreign). Postmaster: Send address change to ELECTRIC LIGHT & POWER, P.O. Box 1030, Barrington IL 60010.

ABP
BPA

Advertiser and advertising agency assume liability for all contents (including text representation and illustrations) of advertisements printed, and also assume responsibility for any claims arising therefrom made against the publisher. It is the advertiser's or agency's responsibility to obtain appropriate releases on any items or individuals pictured in the advertisement.